Climate Change and Energy Perspectives

Editors: Johan Eyckmans, Guido Pepermans, Stef Proost

Introduction

This book deals with climate change and energy problems and is the result of research cooperation within the unit Energy, Transport and Environment at the Center of Economic Studies of the K.U.Leuven. The research unit consists of academics and researchers of the K.U.Leuven Association (HUBrussel and Faculty of Economics and Business – K.U.Leuven).

Climate Change is a long term environmental problem at world scale. In order to limit climate change, strong reductions of Greenhouse Gas (GHG) emissions are required. As the carbon emissions associated to fossil energy use are responsible for the bulk of the GHG emissions, this will require vigorous actions on the energy front. One will need strong energy saving actions as well as a substitution of fossil energy by non fossil, renewable energy sources.

The book consists of five contributed chapters. As climate change is an international policy problem, the two first chapters are contributions by international experts in the field of climate change, technology and renewables policy. The three other chapters discuss energy and climate policy questions at the Belgian and Flanders level.

In the first chapter **Carolyn Fischer** (Resources for the Future, Washington DC) outlines some core principles for guiding the design of clean technology policies, with a focus on energy. She points out the necessary ingredients for a successful clean technology policy. The first is a strong pricing signal that carbon emissions are costly, this can take the form of a tradable emissions scheme or a carbon tax. The second is to create an environment where the market picks the right new technologies. This includes removing distorting subsidies and barriers to competition and supporting R&D broadly. Supporting R&D for new energy technologies may require some specific measures. One of the difficult questions is the role of the government in allocating research funds. The author shows that when the government lacks the impartiality and expertise for the allocation of research funds, there exist alternative mechanisms.

In the second chapter, **Karsten Neuhoff** (University of Cambridge, DIW Berlin) analyzes in more debt the European Renewables Directive. This directive requires Member States to deliver by 2020 on average 20% of their final energy consumption using renewable energy sources. To deliver this target, Member States have to adjust not only their renewable pricing and subsidy policies but also many other policy dimensions. These include adapted planning procedures, a check of the energy market design, provide grid and supply infrastructure, and implement support schemes that limit regulatory risk for finance. A failure to pursue any one of these changes risks the successful deployment of renewables. The chapter analyzes how quantitative policy indicators can allow governments to measure and manage the successful implementation of all these policy dimensions to deliver the renewable energy targets. The indicators need to be designed so that they can focus on individual components of the policy framework. Then they can measure whether the envisaged annual deployment level of a technology is compatible with the framework in place in a country. Increased transparency provided by policy indicators facilitates management of policy implementation, enhances accountability of governments and can inform the reporting of Member States to the European Commission. This allows technology companies to have confidence in projected deployment levels and triggers private sector investment in the supply chain to provide the necessary production capacity.

The chapter of **Johan Eyckmans & Sandra Rousseau** (HUBrussel and K.U.Leuven) analyzes the allocation of tradable carbon emission permits in Belgium, more particularly the allocation to installations for the first phase (2005-2007) of the EU ETS. Interesting about Belgium is that its National Allocation Plan is the sum of three different regional allocation plans because environmental policy has to a large extent been regionalized. The data shows that, overall, Belgian installations have been allocated long, i.e. have been given more allowances than what they need to cover their verified emissions, during all years of Phase 1.

Johan Eyckmans & Guido Pepermans (HUBrussel and K.U.Leuven) study in their chapter the contentious issue of the use of nuclear power stations in Belgium. They sketch advantages and disadvantages of particular policy options, and include in their trade-offs issues of market power in the electricity market, external costs of power generation technologies and security of supply.

In the fifth chapter, **Wouter Nijs** (VITO) and **Denise Van Regemorter** (K.U.Leuven), use the Belgian TIMES model to study the costs of the renewable energy target for Belgium and its interactions with the climate policy targets. TIMES is a techno-economic optimisation model which assembles, in a simple market context, technological information (conversion efficiency, investment and variable costs, emissions, etc.) for the entire energy system. With a complete model of the Belgian energy market, they show what are the effects of strengthening or relaxing the renewable target and the potential effects of opening the EU market for trade in green certificates.

The editors acknowledge the financial support of the NBB grant to the K.U.Leuven Association.

Johan Eyckmans (HUBrussel & K.U.Leuven)
Guido Pepermans (HUBrussel & K.U.Leuven)
Stef Proost (K.U.Leuven)

The Role of Technology Policies in Climate Mitigation

Carolyn Fischer*

* Carolyn Fischer is a Senior Fellow at Resources for the Future, 1616 P Street, Washington, DC 20036 USA. The author is grateful for helpful comments from Alex Long, Dave Sawyer, Thomas Sterner, David Popp, and Knut Einar Rosendahl.

Stabilizing global greenhouse gas (GHG) concentrations at levels to avoid significant climate risks will require massive decarbonization of all the major economies over the next few decades. Additional activities will be required to reduce emissions from other GHGs and to promote carbon sequestration through soil management, afforestation, and avoided deforestation. Achieving the necessary scale of emissions reductions will require a multi-faceted policy effort to support a broad array of technological and behavioral changes. This chapter outlines some core principles for guiding the design of clean technology policies, with a focus on energy.

1. Carbon pricing **is** a technology policy

At the core of any cost-effective approach must be a strong and increasing price signal across the entire economy that carbon emissions are costly. Emissions pricing can be implemented either through a carbon tax or a broad-based cap-and-trade system. The reason for a primary reliance on carbon pricing is twofold.

First, technologies are only useful if people want to use them. While social values may influence some folks to become early adopters of hybrid cars or compact-fluorescent light bulbs, financial self-interest is the primary driver of such decisions for most participants in a market economy. Carbon pricing makes clean technologies more cost-competitive, which provides "market pull" by encouraging their adoption. Greater potential for uptake in turn encourages the private sector to innovate improvements and alternatives. Thus, carbon pricing reduces some of the need for reliance on public innovation programs targeted specifically toward clean energy, as the market has more incentive to contribute. Furthermore, carbon pricing ensures that public spending on "market push" strategies of research, development, and deployment (RD&D) ultimately has greater impact, by increasing demand for these technologies.[1]

Second, many options are available for reducing emissions. Not only is there a huge array of technological solutions for electricity generation, production processes, building materials, and consumer appliances, but a variety of behavioral changes can contribute to smaller emissions footprints. No command-and-control regulation could efficiently prescribe all the appropriate activities that should be undertaken. Carbon pricing, on the other hand, creates incentives to do all these things: use less carbon-intensive fuels and products, conserve energy, and develop and deploy emissions-reducing technologies.

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1 For a broader discussion of the interaction between emissions pricing, spillovers, and public support for environmentally friendly technologies, see Fischer (2008).

All of these options will compete in the marketplace, allowing decisions for reducing emissions to be made on the basis of cost-effectiveness. Furthermore, when cost-effective reductions are taken in the near term with current technologies, some pressure is lifted on the speed and depth of technological change needed in the future to reach a long-term cumulative emissions goal.[2]

Technological change and turnover will be essential for deep reductions; however, a lack of emissions pricing is not the only roadblock. In the following sections we discuss a host of other impediments to a robust market for clean technology RD&D: financial, regulatory, behavioral, and network barriers; knowledge and innovation spillovers; scale economies and other challenges. Furthermore, political realities may constrain the carbon price from being sufficiently high and credible as to induce the necessary transformation and innovation. Thus, while experts agree that a carbon price is necessary, few believe that a carbon price alone is sufficient to achieve these goals cost effectively. The carbon price should be supported by complementary policies to address barriers to technological development and deployment.

2. Pick winning technology **policies**

Many studies have been conducted of the technological options for achieving deep reductions in GHG emissions. In a well-known *Science* article, Pacala and Socolow (2004), professors of ecology and engineering at Princeton University, introduced a now popular tool illustrating the "wedges" of potential reductions from available technologies to bring the emissions path to a stabilization target. These kinds of studies are informative, but they focus on the capacity of technologies, rather than the cost-effectiveness of reduction options, the possibilities for innovation over time, or the role of policies in getting there. Economists who model climate policies, on the other hand, tend to focus on cost-effective solutions, but often with less technological detail. All models have difficulty incorporating realistic representations of technological change, uncertainties, barriers, and non-market-based policies. It is important to remember that energy projections are difficult for proven technologies, much less emerging ones.

In one word, a key challenge for meeting emissions and technology goals is "uncertainty." We are not sure what emissions reductions will ultimately be needed or what the corresponding prices will be. We do not necessarily have

2 Fischer and Newell (2008) show that, even with knowledge spillovers, policy cost-effectiveness depends largely on the degree to which all options for reducing emissions are encouraged. While emissions pricing is the single most effective policy, an optimal portfolio also includes R&D support, achieving emission reductions at significantly lower cost than any single policy.

a good idea of the costs of large-scale deployment of currently existing technologies, much less when breakthrough technologies might arrive, or to what degree the costs and/or quality of existing technologies will be improved. These kinds of uncertainties can create a tension among policy recommendations. On the one hand, policies should be as neutral as possible, to allow a broad range of technologies to emerge and compete, and to avoid the problem of governments attempting to pick winners. On the other hand, we cannot be fully neutral, given that we are largely aware of the major technological options that will be available over the next decades and some technologies have specific barriers and specific potentials that may require targeted assistance. The next section discusses which kinds of problems are best addressed with broad support and which kinds may justify narrower policy responses.

3. Address barriers

In a sense, the carbon price is addressing the primary barrier, which has been the lack of financial reward for climate-friendly behavior and technologies. However, additional barriers or market failures may require additional policy tools, and many of these need not target specific technologies.

3.1 Certain barriers lend themselves to broad and neutral policies

Supporting research. For example, the social value of research and innovation often surpasses what the innovators themselves can appropriate. These knowledge "spillovers" represent a kind of market failure, since by receiving only a fraction of the benefits, innovators have only a fraction of the incentive to engage in the R&D. Studies of commercial innovations suggest that, on average, less than half of the gains to R&D return to the originator, although appropriation rates vary considerably over different types of innovations.[3] Basic research, in particular, is an excellent candidate for government support, as the commercial applications are often distant and unknown. Other technologies may become commercially viable, but only when the carbon price is high enough. Although greater stringency of climate policies may be expected in the future, patent lifetimes are still limited. Therefore, the appropriation rates for climate-friendly technologies are likely to be relatively low, at least initially, and rising over time, meaning some extra support during the transition can help clean technology development (Gerlagh et al. 2008). Even commercial innovations have spillovers—however, it is important to remember that spillovers are not the exclusive domain of clean energy technologies. With a

3 See, e.g., Jones and Williams (1998).

carbon price in place, tax breaks and other public incentives for reflecting the additional social value of R&D are most efficient when they are broad-based. Else one risks crowding out useful innovation in other sectors.

Removing distortions. In addition to the carbon price, other policies can ensure that the allocation of private R&D better follows social (including environmental) values. For instance, distorting subsidies for fossil-based energy should be removed. In non-OECD countries, subsidies are primarily used to keep consumer prices artificially low, with overconsumption as a result. If major developing countries would wipe out all energy subsidies, global CO_2 emissions could fall by 4-5% (IEA 2002). In OECD countries, however, most of these subsidies are for fossil-fuel production; for example, in the U.S., half of energy subsidies go to fossil fuels, compared to 5% for renewables (IEA 2006).[4] Of course, beneficiaries of subsidies will resist reform. Therefore, removing subsidies may require a gradual phasing out (French coal subsidies were reduced in a 20-year program); transitioning to less distortionary forms of assistance (the U.S. replaced agricultural commodity price supports with a direct income support program); and educating the public about the benefits to rally support (IEA 2002).

Another kind of subsidy is the lack of policy to reflect the cost of other environmental damages, besides GHG emissions. Regulating conventional air and water pollutants with market-based mechanisms will also help improve market signals and make clean energy sources relatively more competitive to their fossil-fuel counterparts.

Inefficient regulations, on the other hand, can impede technical progress. Unnecessary legal and regulatory barriers that favor incumbents should be removed to allow for better competition. Unfortunately, some of the energy sectors most relevant for GHG reductions also involve highly concentrated, natural monopolies. For example, regulators of power generation, transmission and delivery must keep an eye on the ability of new entrants to join and compete. Licensing, regulations, and interconnection procedures must be clear, not overly burdensome, and coordinated across jurisdictions, while allowing for appropriate oversight to balance potential tradeoffs in economic and environmental costs. Often, streamlining regulations need not be technology-specific and can benefit all participants, not just new green entrants.

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4 Many of these subsidies take the form of preferential tax treatment, relative to other sectors. For example, the oil and gas industries in the U.S. and Canada have benefited from such provisions as accelerated depreciation, the expensing of exploration and development costs, and other investment tax breaks; direct expenditures on infrastructure and R&D; and the incomplete capture of resource rents through royalties—many of which disproportionately support the development of the relatively dirty oil sands (Taylor et al. 2005).

New technologies may also require explicit new policies to create regulatory certainty. For example, the long-term impacts of large-scale carbon capture and sequestration (CCS) remain uncertain, and relevant regulations, guidelines, and industry protocols are needed to assign liability and develop good practices.

3.2 Some barriers may be general in origin, but require more specific attention

Information. For markets to function, they require not only good property rights and competition, but also information. Some product characteristics are easily observable, but others — like nutritional content or energy consumption rates — are not available or credible without government intervention. By improving the availability and visibility of information, product-specific labels, credible reporting standards, and educational campaigns can allow better consumer and firm decision-making at lower costs.

Standards. Still, perfect information may not be enough. Consumer uncertainty about energy prices and the quality and reliability of the new technologies being offered them can contribute to seemingly myopic behavior. Poor choices can also arise when those making decisions about the energy-using appliances and building features are not the same people as those using or paying for the energy, such as in landlord-tenant relationships. Coping with short payback horizons and principal-agent problems can require product-specific interventions, such as energy efficiency standards, fuel-economy standards, and building codes. While these standards are generally informed by technological options, they need not be prescriptive of particular ways to meet the standards. Indeed, they should be designed so as to allow cost-effective alternatives and ongoing incentives for improvement.

Financing. Risk and payback horizons also influence investment decisions; if the private perceptions of these factors do not align with the public ones, then policies may be needed to assist financing and manage risks for publicly desirable projects. Technologies for which capital costs are very large (such as nuclear, hydro, CCS) are more likely to need preferential financing or guarantees to reduce private investment risks. Even wind generation has high capital costs relative to operating costs; however, the capacity can be expanded more incrementally and policies to guarantee profitable production prices has typically been used to reduce investment risk, rather than finance guarantees, although investment tax credits are also common. Ultimately, greater certainty about the carbon pricing policy will also help to reduce risks and raise returns for low-carbon technologies, and financing interventions should focus on narrowing the discrepancy between private and public payback horizons.

3.3 Other barriers are specific to certain technologies

Scale economies. Economies of scale are an issue for many new technologies. Until enough units have penetrated the market, production costs are high and support services are scarce. Policies to address this barrier can legitimately help some new technologies gain acceptance and get off the ground, but they should be careful to avoid extended support for uneconomic technologies. An example is hybrid vehicle tax credits in the U.S., which phase out after a certain number of models are sold. Portfolio standards also become easier to meet (and credit prices fall) as scale economies are met.

Networks and infrastructure. Some technological options require new infrastructure and support networks in order to function. However, private actors are reluctant to take on activities that supply public goods, and most would prefer to wait for someone else to do it. The resulting network externalities are an important cause of "path dependence" or "technological lock-in," and public intervention may be required to change paths. Important examples lie in the distribution of fuels for transport: biofuels, hydrogen, CNG, or plug-in electric would require new fuel (or battery) distribution and storage equipment, as well as new vehicle engines. Here it may be costly to allow multiple new options and thereby difficult to avoid picking a winner, so the decision must be made deliberately. For costly network infrastructure investments, there is an option value to waiting for more information, in order to be confident in betting on the technology.

Some infrastructure investments for carbon-free generation technologies may also have network externalities. For example, real-time energy metering can allow for time-of-use pricing to better manage electricity demand. Direct current lines in buildings could allow solar cells to power many devices without inverters. Upgrades to "smart grid" transmission technologies can facilitate the incorporation of distributed generation and intermittent renewable energy sources. However, many infrastructure investments—like transmission lines for remote renewable energy sources—are better viewed as an additional cost to developing more capacity in those resources, although there may be other barriers related to siting or entry. The expansion of nuclear generation would require central infrastructure in the form of a waste storage facility—which involves its own tradeoffs.

Tradeoffs. Many technologies that reduce GHGs may instead cause other environmental damages and risks. For example, nuclear generation creates radioactive waste and security concerns. Hydropower affects aquatic ecosystems, fish spawning, and cultural resource access rights. Battery waste involves toxic chemicals; transmission lines can disturb other land uses; most generation siting raises "not in my backyard" (NIMBY) issues, and the list goes on. Public assessment of the tradeoffs is needed before allowing broad deployment. These assessments are also related to the regulatory regime for deploying technologies, and assuring that regime is appropriate but not unnecessarily long or cumbersome.

4. Certain kinds of technologies may deserve preferential treatment

In addition to addressing important market failures and barriers, policymakers may want to direct extra attention and support to certain kinds of technologies that have special potential. Some examples of especially desirable technologies are those that expand options and reduce costs of reaching deep reductions, those that may have additional spillover benefits at home, and those that may have spillover benefits abroad, further reducing global emissions and improving the likelihood of more globally stringent GHG agreements.

Backstop technologies. As heavily emphasized in the Stern Review (2006), there is an important role for technology policies that focus on bringing down the costs of reducing carbon emissions. When the future emissions target is uncertain, as well as the costs of reaching potential targets, both R&D and early abatement activities can facilitate the adoption of more ambitious targets and thus help reduce the expected costs of future abatement, adaptation, and damages. However, certain kinds of R&D may also help to reduce the degree of uncertainty in these costs and thereby carry an extra value.

In the climate policy case, the national or societal marginal abatement cost curve represents a sequence of technological options, each more costly than its predecessor. "Backstop" technologies are a particular kind of option. Conceptually, a true backstop technology is free to be replicated at a large scale without scarcity constraints, meaning that marginal costs (though relatively high) do not increase much as capacity is expanded. The presence of backstop technologies helps to flatten out the upper portion of the overall marginal abatement curve, meaning that if stricter-than-expected emissions targets are necessary, carbon prices will not need to rise astronomically. In other words, if it turns out that climate change is even more serious than we think, and we need to step up emission reductions dramatically in the future, an affordable backstop that can be expanded to basically any scale would be invaluable. Therefore, given the uncertainty we face, there is an added value to bringing down the costs of technologies that help flatten the marginal abatement cost curve. Of course, another way to keep options open is by reducing emissions more aggressively in the near term. But if backstop technologies can keep costs lower in the worst-case scenarios, expected long-term costs are also lower, and that in turn reduces pressure to engage in deeper reductions in the near term.[5]

In terms of true backstop technologies, the most-discussed candidates are carbon capture and storage, nuclear, and solar (and, theoretically, fusion). Each has the possibility of being utilized at large scales, though location (and risk management) could be a constraining factor. The solar energy flow to earth is particularly large in comparison to societal needs. RD&D programs that can lower costs, expand capacities, and accelerate how rapidly these capacities can be tapped have an added insurance value, beyond the gains that would be realized at the expected levels of utilization laid out in roadmaps.

Comparative advantage. Countries may have national RD&D policies, but the development of new technologies is a global effort. Consequently, there may be opportunities for coordination (or free-riding, for that matter) and for specialization. Technology oriented agreements can be aimed at knowledge sharing and coordination, research, development or demonstration, and even deployment.[6] Such commitments can increase the technological effectiveness of an agreement over emissions reductions, although they are generally weak policies in terms of environmental effectiveness on their own. (Even at the international level, technology policies are complements to mitigation policies.) International agreements over technology standards can also be attractive from a competitiveness point of view, ensuring that trading partners have similar cost burdens.

On the other hand, technologies might become a source of competitiveness. Due to different circumstances, some countries will enjoy a comparative advantage in certain technologies. In this case, not all countries will want to engage in the same RD&D portfolio, but rather wish to specialize to some extent. For example, countries with large availability of geological sequestration sites may prefer to invest more in CCS innovation.

Global spillovers. Technology spillovers do not respect borders either, and they can inform priorities for dealing with global pollutants like GHGs. In particular, technological advances that support international agreements and efforts have additional value beyond what is appropriated at home. For example, some technologies may have better potential to be adopted among emerging economies that lack direct carbon regulation. Indeed, the availability of low-cost abatement opportunities may help encourage these countries ultimately to take on hard emissions targets. Thus, developed countries will want to en-

5 See Fischer and Sterner (2007).
6 For a discussion of technology oriented agreements, see de Coninck et al. (2008).

gage not only in technology transfer agreements, but also RD&D efforts that are likely to produce technologies to be transferred.[7]

5. Summary and options

We should recognize that not all barriers to adoption are market failures. Cost, reliability and quality issues, risk, etc., are all legitimate aspects that the market should be allowed to weigh in choosing cost-effective technologies. Furthermore, R&D market failures are not exclusive to energy technologies, and once most energy-related market failures are addressed (as through carbon pricing), then society must be wary of crowding out other legitimate innovation efforts.

As a result, the main tools for encouraging climate-friendly technologies should be those that encourage the market to make good choices more generally: pricing carbon emissions and other environmental damages, removing distorting subsidies and barriers to competition, and supporting R&D broadly.

Some technologies face particular barriers, requiring society to take a decision of whether to support them, committing to major infrastructure investments or environmental risks. Other technologies may merit extra support, because they offer insurance against the possible need for deeper reductions, or because they have greater potential for being adopted in other parts of the world.

Several policy options are available to support technological development. Broad-based policies include R&D tax credits, funding universities and research institutions, and other public support for research through competitive grant processes. Scale economies can be supported through tax breaks, subsidies, performance standards (including tradable ones), or market-share mandates. While the latter two policies also create an implicit subsidy to the targeted technology (like renewable energy sources), paid for by the non-preferred sources, they have the advantage of not only requiring no public outlays, but also naturally phasing itself out as the new technology becomes cost-competitive.

More specific policies are required to address particular market failures and barriers, including information requirements, energy efficiency standards, building codes, etc. In these cases, policies will generally be more effective, the more closely they target the specific market failure, as opposed to a specific technology. Standards perform better when they are flexible rather than prescriptive in terms of how the goal must be achieved.

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7 See also Popp (2008) for insights into technology transfer policies.

Finally, for those technologies identified as being particularly desirable, some narrower R&D policies are available. Traditionally, most policies subsidize inputs to research, either through specific tax credits, grants or contracts, or directed research in publicly funded laboratories. If government lacks the expertise or impartiality, allocation of these research funds can also be outsourced to independent third-party managers given specific mandates.[8] Technology prizes, on the other hand, offer financial inducement to an output, such as being the first to develop a specific advance or the contestant having made the most progress by a deadline. Newell and Wilson (2005) indicate that such methods have been successful in the past and they could play a supportive role in climate policy, although attention should be paid to the design features, including the technological target, the size and nature of the prize, and the method for selecting the winner.

International engagement is another component of technology policy. Recognizing that climate mitigation and technological advances are a global effort, countries can leverage their own R&D resources with international partnerships and agreements to encourage knowledge sharing and broaden the markets for new technologies.

Ultimately, the biggest driver of technological adoption and change will be the mitigation policy, which determines the demand for those technologies. An additional advantage of emissions pricing policies is their ability to generate revenue, which can fund help fund the complementary technology programs. However, that is not to say that all or even a particular share of those revenues needs to be explicitly earmarked for technology programs. Indeed, just as technologies should compete in the marketplace for adoption, technology policies should compete in the budget among all the worthy causes. Supporting climate-friendly RD&D is certainly one, but so are transitional assistance, adaptation, tax relief, foreign aid, and a host of other demands unrelated to climate, including other innovations. Priority should be given to policies that enhance overall economic efficiency—broad R&D support, removing distortions, addressing regulatory barriers, reducing tax burdens, improving information, supporting fundamental research. Then policymakers can turn to more targeted programs, fully considering the benefits and the tradeoffs.

8 An example is the Ontario Centres of Excellence, which operate somewhat like a publicly funded venture capital firm.

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Implementing the EU Renewables Directive

Karsten Neuhoff*

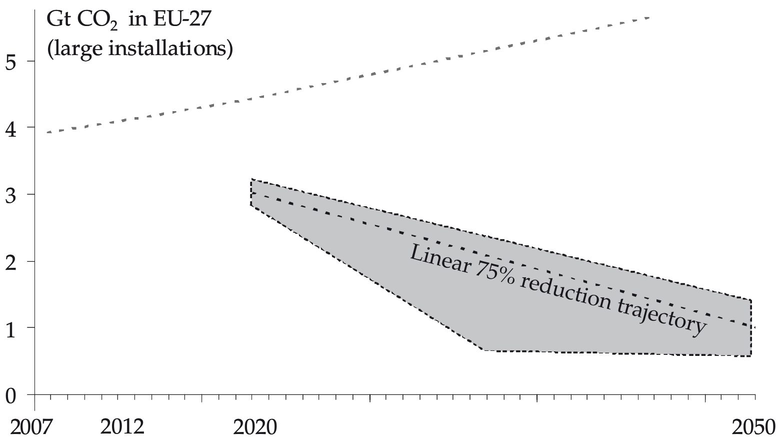
* Research support from the project SuperGen Flexnet and the UK research council project TSEC, is gratefully acknowledged. I am grateful to participants at a seminar in Leuven and to Mario Ragwitz for detailed comments and for research support to Sarah Lester.

1. Introduction

In December 2008 the European Parliament, Council and Commission passed a Renewables Directive that obliges Europe to increase the share of renewable energy from 6% to 20% of final energy by 2020. This is a visionary policy that creates an opportunity for Europe to move towards a long-term climate stabilisation scenario.

Figure 1 illustrates that the gap between business as usual emissions and the emission level that is compatible with stabilisation of carbon emissions at 450ppm is increasing over time. While initial emission reductions might be viable with efficiency improvements and fuel shifting; the final emission target can only be achieved with continued economic growth in large shares of renewable energy (Stern 2006).

Figure 1. Stylised emission trajectory – business as usual versus stabilisation scenario



The Renewables Directive ensures that the European economy can move along the emission reduction trajectory while continuing the use of energy and economic success. The Directive supports investment in the future of European economy and society, in a similar fashion to the previous public investment in schooling and Universities that enhanced European competitiveness and wellbeing. Governments can, however, fail to implement strategic decisions in the struggle to keep up with their day to day business. Three critical factors influence the successful implementation of the Renewables Directive:

First, large scale deployment of renewable energy sources requires changes to financial support schemes, network regulation, regional planning, permitting processes, and energy market design. If any one of the changes is not pursued effectively, then deployment will be halted in the respective country.

Second, renewable energy sources are in competition with conventional and nuclear energy and can reduce the value of some coal and nuclear power stations. This can create incentives for some utilities to lobby against renewables or to obstruct their deployment. The typical strategy of such lobbyists is to request delayed action until the information base is improved, as successfully demonstrated by oil and power companies during the Bush administration.

Third, industry has ample experience with the volatility of government policies, as a result private companies hesitantly invest in production capacity for wind turbines when demand depends on future government decisions. Without early private sector investment in the supply chain, however, the achievement of the renewable targets will be expensive or difficult.

This chapter discusses how quantitative policy indicators and targets for selected aspects of the policy framework can

- contribute to effective and comprehensive implementation of national policy frameworks to facilitate sufficient deployment of renewables.
- enhance accountability of politicians, senior civil servants and private sector actors for future generations.
- increase the visibility of policy for the private sector to facilitate early investments in the supply chain.

By 30th of June 2009 the European Commission had to provide guidance for Member States on the reporting of their national renewable action plans. Quantitative policy indicators could form part of the template for this reporting. Indicators can increase the visibility of future renewable markets – and thus facilitate private sector investment in the supply chain and projecting activities. Confidence in growing markets also encourages firms to invest in innovative activities and increase their exploration of cost reductions options, thus increasing the benefits of renewables policy (Aghion et al 1997; Neuhoff et al 2007).

2. How much guidance from governments?

Background

With the liberalisation of energy markets, governments shifted responsibility for purchasing, investment and operation decisions to the private sector. This was expected to deliver strong incentives for cost and price reductions, more economic technology choices and better project execution.

The theoretical model of liberalised energy markets envisages that governments limit themselves to setting the market design and a clear regulatory framework. Production and delivery of energy becomes the responsibility of private firms.

In practice the public perceives energy provision as a public service and holds governments responsible for excessive prices or supply interruptions. This creates strong incentives for government to intervene in the market. The clear regulatory and market interface between government and energy companies sometimes becomes blurred. This is illustrated by the response of UK power companies to government pressure; 'voluntary' commitments are offered by power companies to support the fuel poor.

In contrast to such implicit government interventions, renewable energy support schemes are explicit market interventions. Three types of market failures are cited as justification for the deviation from the technology-neutral energy market regulation. First, initial costs of early stage technologies are high and are decreasing with experience and learning about the technology (IEA 2000). Even companies that did not invest in the new technologies themselves, can benefit from these insights and produce the new technology at low costs. The initial investor does not capture these benefits for society, and reduces investment in the new technology below the socially optimal level without government support. Second, incomplete cost internalisation of environmental and security of supply externalities for conventional technologies (Grubb et al 2005; Roques e.a. 2006). Third, barriers set up by incumbent companies limit competition in new technology fields where they do not have incumbent advantages; disadvantages in scale, management expertise, and contractual arrangements with the supply chain limit the number of entrants to renewable markets.

These market failures have often been cited to justify renewable support schemes that often aim to deliver 21% renewable electricity as required by the 2001 Directive (Directive 2001/77/EC (2001). Is there a continued need for technology-specific support for much larger penetration levels, with many studies pointing to 30-40% of electricity to be produced from renewable sources by 2020?

Need for continued support of renewable technologies?

For some technologies, such as on-shore wind, deployment has reached a scale at which learning externalities are declining and costs are becoming increasingly competitive with conventional generation technologies. For other renewable technologies, the infant nature of the industries means they can only achieve large scale deployment and learning benefits with technology specific support programs. (BERR 2008).

In theory, carbon pricing mechanisms and cap and trade systems will result in the internalisation of environmental externalities, for example the carbon price created by European Union Emission Trading scheme. Industry pressure, however, has resulted in generous provisions for the use of cheap CDM credits instead of domestic mitigation efforts, subsequently causing a weak carbon price (Carbon Trust 2009 Forthcoming).. A low carbon price might result in continued investment in high-carbon energy infrastructures, which is incompatible with the long-term emission reduction targets and will result in such infrastructure being stranded as more stringent regulation is implemented. Renewable targets can shift the focus of industry investment and reduce the risk of such stranded investment for the competitiveness of European industry.

The market structure of energy markets has not improved over recent years - and corporate strategies in the utility sector often remain reactive to regulatory policy, rather than pro-active in renewable energy technologies. As a result, concern remains whether new technologies will receive sufficient support from incumbent companies. Renewable support, designed in a way that is accessible for new-entrant companies, will therefore remain important. Thus the threat of entry – whether subsequent materialised or pre-empted by investment from the incumbents – is crucial to ensure that democratic decisions can be implemented even where they might not be shared by leaders of some incumbent companies.

These benefits of direct government intervention in technology choice need to be weighted against risks of negative impacts on incentives for decisive project execution, efficient operation, economic and innovative investment choices. In contrast to part technology projects that were directly managed by government, or executed by monopolistic utilities that could pass all cost to consumers, renewable projects are implemented in market environments. Feed-in-tariffs, tender auctions, or traded certificate schemes define the price or premium for renewable energy. As in any market environment, project developers retain profits from good negotiations with technology suppliers and engineering companies but also bear the risks of underperforming or delayed projects.

Renewable energy targets, pursued with effective policies, retain the incentives for efficient project execution and operation through the allocation of project risk to the project developer and operator. With a clear market interface between private sector actors and the government, the risk of regulatory capture is limited as no public administrator is required to accompany individual energy projects over long periods of time. Thus the 'cost' of renewable energy targets in terms of reduced efficiency of liberalised energy markets is limited to the desired impact on the technology choice.

The European Parliament, Commission and Member State governments represented in the European Council have passed a Renewables Directive that specifies clear renewable targets and compliance mechanisms. The next section discusses whether the market requires further guidance from governments for technology choice, timing and regional distribution of renewable investments within their countries.

How specific to design the guidance for renewables?

Without guidance on technology choice, private sector actors would focus on least cost renewable energy technologies, currently on-shore wind, bio-mass and biog-gas from sewage and landfill. Cost of other renewable technologies, however, will decline with increased deployment and initial support. If such support is available, valuable options for the renewable portfolio can be developed. Without other renewable technology options it will be difficult to provide the overall volume of renewable energy required, and more costly to deliver energy at the time and location where it is required (Ragwitz et al 2007). For example the DENA study pointed to the need of 800km additional transmission lines within Germany by 2015 (DENA 2005).

Without guidance on the timing of investments in specific technologies, it is difficult for the technology supply chain to invest in the necessary technological improvements and production capacities. If the demand for a product is delayed by a few years, then the producer will lose the necessary trained staff, revenue and possibly go bankrupt. If the demand for a certain technology is unexpectedly high, then the necessary production capacity is missing and scarcity prices result. Instead of high deployment levels only high deployment costs will be observed.

This suggests governments should clearly define the timing and volume of investment in different renewable energy technologies using appropriate regulatory frameworks. If, however, all European countries specify the exact investment quantities and time frames for specific technologies, then this puts the respective technology producers in a strong bargaining position. After all, the less responsive the demand is to the price of a producer, the higher the price charged in the market.

Renewable support policies have to balance the demand for technology and time specificity, with the need for short-term flexibility in times of real or strategic scarcity prices for specific technologies. For price-based approaches, such as feed-in tariffs, the mechanism to adjust tariffs for new projects over time has to be structured appropriately. For quantity-based approaches, such as tender auctions for off-shore wind farms, an appropriate schedule of late delivery payments for the project can give investors some temporal flexibility to negotiate with technology companies. In either case, it is important to assess the interactions across European support schemes to avoid expensive competition between countries.

Whether national governments also develop some indication for the regional distribution of renewable projects within their country depends on various factors. For wind power, grid expansion costs and system balancing costs can be reduced, if turbines are not only focused on high wind sites, but distributed across the country. Also public acceptance might increase, if there is a clear perception of burden sharing by all citizens. Finally, with better understanding of the anticipated regional distribution of generation investment, grid expansion plans can be better tailored for the expected generation pattern. Obviously, any such guidance needs to make an appropriate trade-off between regional diversification, regional power demand, grid expansion costs and regional resource availability.

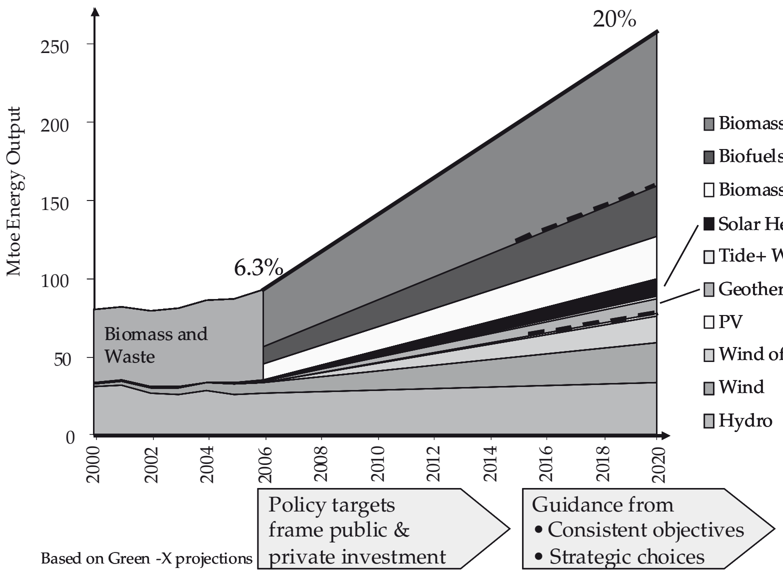
Initial renewable support schemes, for example in Germany during the 1990s, had regional specific components as they were often supported by cities or states. As renewable support schemes are now mainly at the national level, this specificity was lost. This was initially envisaged to encourage the development of the most suitable sites. Increasingly ambitious renewable targets, however, have shifted the objective from cherry picking the very best sites to large scales harvesting of renewable energy resources. Refocusing the objective towards local ownership might result in a renewed shift to define policy with regional targets. After all, in other policy fields regional sharing, for example joint responsibility for schooling and training, is common practice and contributes to a sense of local ownership that increases public support.

A pragmatic approach

It is difficult to prescribe and commit to the exact technology mix or distribution of investment within countries for 2020, however, it would also be difficult to deliver the renewable targets without any guidance. A pragmatic solution might be to offer more specific guidance during the initial project phases, which merge towards a broader objective further in the future. Thus longer-term targets can provide guidance if they (i) reflect a similar level of ambition to the current policy, (ii) seem viable given current technology expectations, and (iii) are in line with the environmental requirements of climate stabilisation.

Figure 2 illustrates how countries can define specific targets for individual technology bands, for example for the time frame up to 2015, which are more broadly defined for later years.

Figure 2. Possible evaluation of renewable contribution from different technologies (Source: based on Green X projections).



3. What policy framework is required?

The current infrastructure, planning regime, regulatory and market design have evolved and been tailored for existing technology mixes and fuels. To facilitate renewable development and reduce costs of large scale deployment, this framework needs to be adjusted to match the requirements of renewable energy technologies (for a literature survey see Neuhoff and Sellers 2006).

3.1 Planning

Planning regimes often require complex administrative procedures for energy projects. Large scale conventional power projects often have the technical capacity to overcome this issue, but planning constraints can imply a disproportionate burden for small scale projects.

Determining an adaptable policy framework for planning often requires policy reform: where planning constraints limit development, national governments should take action to reduce such barriers. The text box below outlines the policy reform instigated by the UK government to remove planning constraints and incentivise affordable housing schemes through the use of policy indicators and targets.

The challenge and policy response to planning constraints – example of UK housing sector

A lack of social and affordable housing due to planning constraints, amongst other factors, has lead to: ambitious building targets, increased investment, and planning system reform:

Challenge:

- Difficulties of the number of institutions involved. Public sector: Housing Cooperation, National Housing Federation, Local Planning Authorities, English Partnerships, and housing associations. Private sector: Home Builders federation, planning consultants, and developers.
- Local Planning Authorities and Regional Planning Bodies responsible for the preparation of local development documents and regional spatial strategies

Approach:

- National target: Three million new homes by 2020, two million of which by 2016. Spending Review 2004 target: Increase number of gross affordable homes to 70,000 by 2010/11.
- Local Planning Authorities set regional targets; e.g: London target of 50% affordable homes, new indicative target of 500,000 over next 3 years.
- Implementation: Local Development Documents set out a housing implementation strategy describing management and delivery of housing and land targets and trajectories.
- Section 106 of the Town and Country Planning Act 1990: enables of negotiation of planning agreements to facilitate development of affordable housing and small-scale residential sites.
- Reform of the land use planning system. New Planning Policy Statements for housing (PPS3), new Housing and Planning Delivery Grants for local councils.

Success of policy reform?

S106 agreements have helped: in 2004/05 12% of total output of affordable housing was delivered by S106 affordable dwellings. However, completion of housing stock not rising as rapidly as the number of permissions granted for S106 agreements. This raises questions about the capacity of the planning system to deliver agreed levels of affordable housing.

Spending Review 2004 targets met: provisional figures from the Housing Corporation show that 29,419 (in 2007-08) were provided.

(Sources: Department for Communities and Local Government (2006 and 2007); London government website (2008); Meen and Andrew (2008); Monk et al (2006); Spending Review (2004).

3.2 Infrastructure

Transport, fuel, and electricity networks have evolved, often with public support, for the current power mix. Renewable energy is produced at different locations, and might also use different energy carriers (e.g. larger use of electricity). This will require adjustments to the respective networks. (Grubb et al 2008).

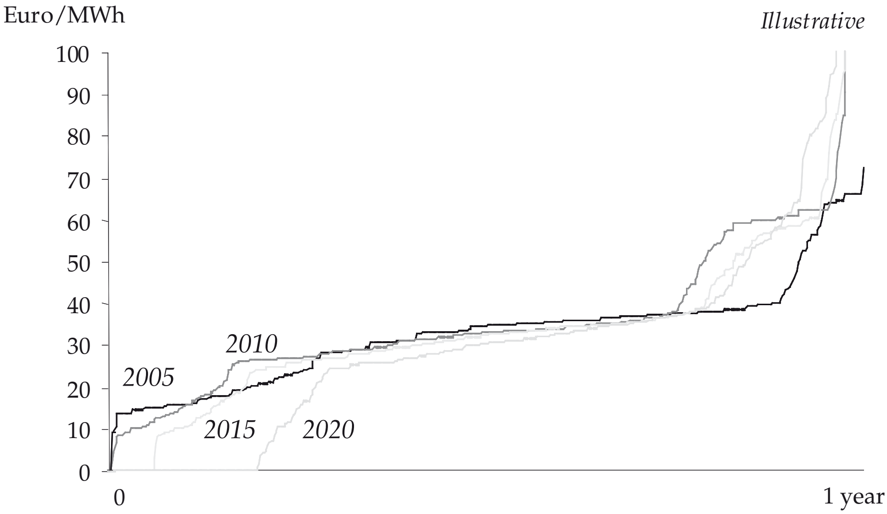
3.3 Market design and regulation

Market design and regulation has been tailored for conventional generation technologies and fuel sources, in order to create appropriate incentives for effective use. The existing market design creates artificial constraints for large scale use of renewable energy technologies:

Figure 3 illustrates simulation results for hourly electricity prices – assuming the UK power system accommodates increasing shares of renewables (e.g. 40% of electric energy from wind power by 2020). The 8760 hourly prices per year have been sorted increasing order. This shows that with increasing penetration of wind power, the electricity price will drop to zero for increasing numbers of hours. This is, because with large shares of wind in the system, wind power production exceeds electricity demand and the value of marginal units of electricity is low or zero. In such hours some wind output might even be spilled.

The lower prices during such hours also reduce the revenue of other power generation that is required to meet demand, e.g. at times of low wind output. The simulation results illustrate that as a result power prices get higher during other periods of the year and thus create the incentive for investment in power generation that can meet demand at times of low output from intermittent generation.

Figure 3. Simulated price-duration curve for one region of the UK with large scale wind power penetration (model description in Neuhoff et al 2008).



The model solution in Figure 3 depicts the results for one region of the country, not for the entire UK. For example, in the North of the UK, wind output might exceed demand and export capacity, resulting in spilling of the wind in this region even when overall demand in the UK could accommodate the surplus. High penetrations of wind power may cause transmission constraints within countries to receive increasing attention. While adapting the network might require some increase of transmission capacity, an efficient solution to power system design will also include some congestion in the network. Building a power line that is only operated for a few hours of the year is more expensive than spilling wind output from turbines in the North of the UK for a few hours per year.

Finally, with increasing penetration of wind power, the output changes from wind turbines require increased responses from both conventional power stations and demand-side to ensure supply matches demand at all times. As prediction accuracy for wind output only improves throughout the day, significant adjustments in power station operation have to be pursued during the day. The current market design does not provide sufficient information exchange and liquidity to allow such adjustments during the day.

This illustrates some of the aspects that future power market design will have to accommodate. Allowing for efficient use of the network and additional connection of power stations even in the presence of some congestion of the network, organising a flexible operation of the power system, and integrating the demand side in providing balancing services, are key to adapting market design for new technologies.

3.4 Financial support schemes

The European Renewable Directive provides Member States with the flexibility to choose their national financial support scheme. Thus a long-standing discussion between feed-in tariffs, certificate schemes, and tender auctions did not have to be resolved at the European level before the Directive could be passed. (Mitchell et al 2006; Ragwitz et al 2006).While most of the arguments for and against the different policy instruments are well known, the larger share of renewables currently required points to additional aspects to be considered.

The volume of investment that will be required to deploy the new renewables has been increased by the 20% target somewhere in the order of 400 billion Euro by 2020.[1] Investment volume does not equate to cost for society because renewable energy technologies such as wind, tidal stream or solar replace future fuel costs. But investment projects require finance.

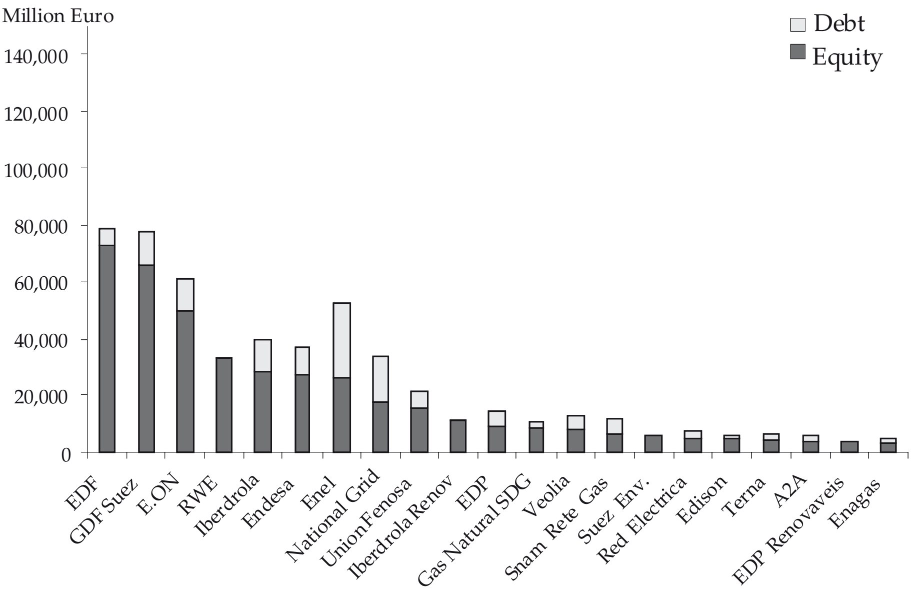
Figure 4 illustrates the finance structure of major European utilities as of November 2008. It shows that following high profits during recent years, utility companies have little debt. ENEL has the highest debt level, with debt corresponding to 50% of the equity level. This is perceived as substantial debt by the market; ENEL has to pay 2.5% more interest for bonds than other utility companies. Assuming all companies listed in Figure 4 would leverage their equity capital with 50% of debt, then they could raise additional 300 billion Euro funding. Obviously this is only a basic initial approximation, which ignores the impact of higher leveraging on share prices, other investment needs, and also excludes some of the utilities.

This rough calculation shows the importance of considering the financial access and investment risk for different renewable policies. The need for bond finance, new equity, or third party entry suggests that financing has to be simple and low risk. Otherwise it may prove impossible to deliver the renewable target. Tradable certificate schemes are unlikely to offer the necessary security – as the schemes combine regulatory risks about the evolution of the market design with market risks about the future scarcity level of renewables. Long-term price guarantees, as possible with feed-in tariffs or tender approaches,

1 Assuming 2/3 of additional renewables (e.g. 1100TWh) are delivered for simplicity of calculation with wind power at 30% load factor and 1000 Euro/KW investment cost, then total cost is 420 billion Euro. This is in line with more detailed results from the Green-X project (2004).

address these concerns and are more suitable to generate the necessary finance.

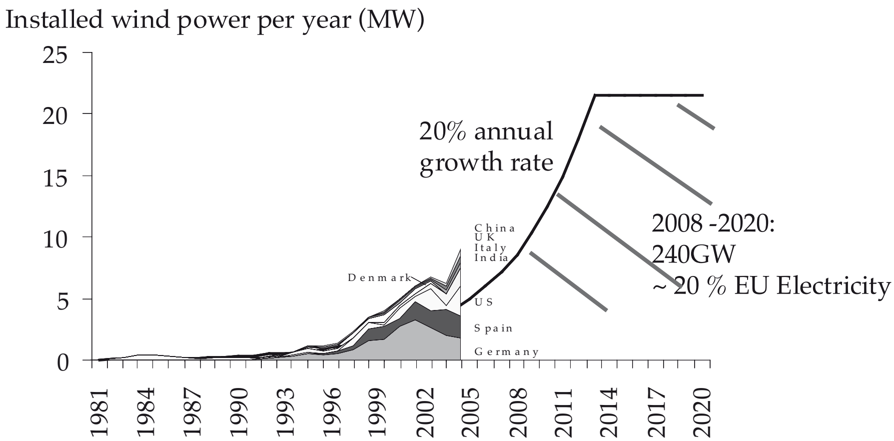
Figure 4. Finance structure of some major European Utilities.



3.5 Supply chain

Delivering of the renewable targets also relies on an increase of the production capacity for renewable energy technologies. For example, if an additional 20% of European electricity is to be delivered from wind power then 240GW of new wind turbines will have to be installed. Figure 5 illustrates that such a deployment is consistent with historic developments of deployment levels, but does require a further doubling of the wind turbine production capacity devoted to the European market.

Figure 5. Annual wind power deployment if 20% additional electricity is produced with wind power. A portfolio of several renewable technologies can reduce the required deployment.



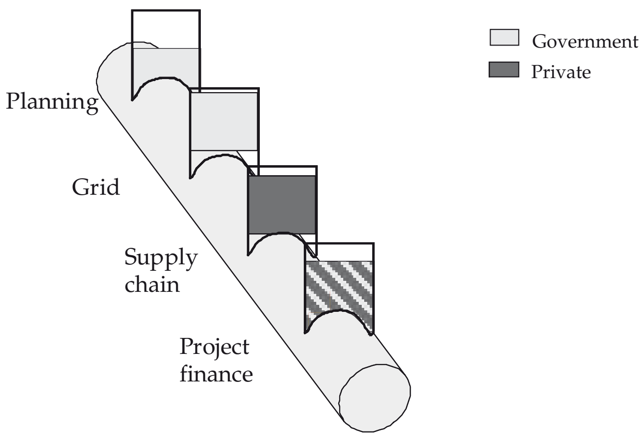
Such a large increase of production capacity and production volumes would be very desirable in the current economic downturn. As the expertise for wind turbine production and the associated supply chain is in the private sector, the necessary investment would also be shouldered by the private sector. The main requirement for this investment is trust in the existence of the future market. Rapid implementation of the Renewables Directive at the Member State level will thus be a central element not only for the delivery of the 2020 target, but also for a quick response by the private sector.

A recent study commissioned by the UK government analysed where bottlenecks are likely to occur in the supply chain (SKM 2008). This is certainly a laudable exercise, but requires further methodological refinement to allow for meaningful insights. For example, the study concluded that a shortage of installation vessels will hamper the deployment of off-shore turbines around the year 2015. If such a shortage is anticipated, then one might expect private sector investors to fill the gap with new vessels. However, if the demand is not anticipated, or if the relevant private sector investors do not have confidence in the demand projections, then bottlenecks can materialise. The enduring shortage of silicon wavers for PV cell production illustrates such an example; producers did not anticipate the continued high growth rates for PV cell production and as a result they did not provide the necessary production capacity.

4. How to ensure the policy framework is in place?

Many aspects of a renewable framework have to be in place to allow for a successful deployment of renewables (Foxon et al 2003). This is illustrated in Figure 6; many policy levers have to be in the right position to allow for the flow of renewable projects. Any one of the levers can stop the flow through the renewable project pipeline. Should renewable project deployment not achieve the desired level then it may not be sufficient to identify one lever that is obstructing deployment, as one blockage might hide the existence of other barriers that only become apparent after the removal of the initial problem. This raises the question of how to design a policy framework to ensure all barriers for renewable deployment are sufficiently removed to allow the necessary flow of renewable projects.

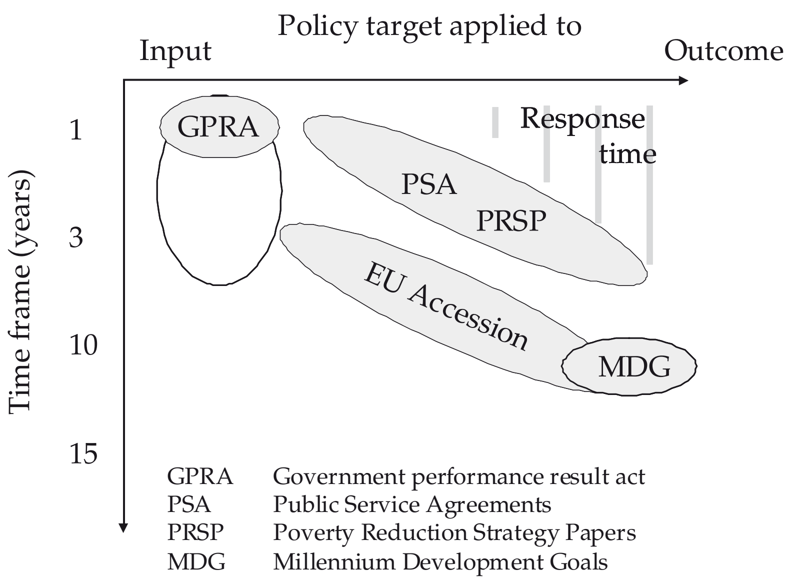
Figure 6. Critical policy levers for the deployment of renewables.



The role of policy indicators

Policy indicators have received an increasing level of attention with regard to policy implementation (see recent review on policy cooperation: ISDCP available at www.climatestrategies.org). Such indicators facilitate benchmarking, information exchange, and monitoring of effective implementation (Cust 2009). The use of indicators has enabled targets to become an integral part of policy design. Amongst other examples, Lester and Neuhoff (2009) summarise how policy targets have been used in the UK domestic context in the negotiation of Public Service Agreements between the local and central government. Examples are also drawn from the Government Performance Results Act of the USA, which sets targets for central administration. Policy targets are also increasingly used in international processes, including in the Poverty Reduction Strategy Papers of the IMF, in the accession process of new Member States to the European Union, and as part of the Millennium Development Goals. Quantitative policy indicators were also successfully used to evaluate the implementation of the renewable electricity Directive 2001/77/EC (European Commission 2005, Ragwitz et al 2006). Therefore quantitative performance indicators have proven their value for monitoring the implementation of European renewable energy targets. They should now be further developed and extended to the heating and transport sector.

Figure 7. Time frames and outcomes used for policy targets.

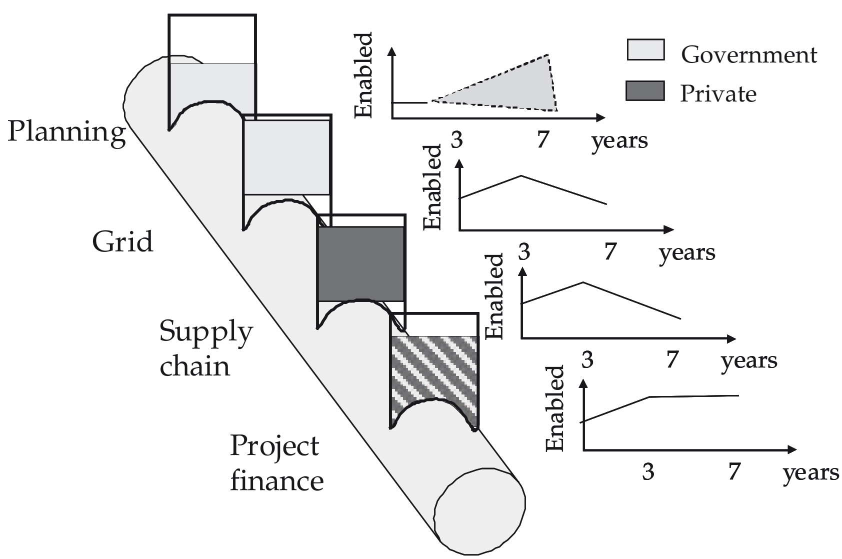


The horizontal axis in Figure 7 shows that for the majority of cases, successful policy targets do not apply to the final outcome measure, such as the share of energy produced from renewables, but usually focus on intermediate indicators. This is beneficial as it allows for shorter timeframes for target definition and implementation, which allows the time-lag from policy implementation to final outcome to be managed. Moving away from final outcomes, however, has the drawback of reducing the flexibility of policy choices; the closer policy targets are linked to inputs, the more prescriptive they become for policy and low-carbon activity. The definition of policy indicators and metrics has to balance the benefits of short-time lags, which allow for effective implementation, and the flexibility provided by outcome-based metrics.

The previous sections have highlighted the challenges for successful deployment of renewable projects; a set of quantitative policy indicators can help contribute to the delivery of the EU Renewables Directive.

The projection of technological capacity, regional efficiency, and time-scales for renewable deployment should be the starting point for the design of such indicators. It is also critical that any metrics are compatible with the national renewable target. Policy indicators can then quantify what percentage of the estimated project investment is compatible with the evolving policy framework. Figure 8 illustrates this approach; detailing the time-scales of the removal of barriers needed to implement a successful renewables policy. For example, a country may currently face some constraints for renewables deployment due to planning processes, but is pursuing a change to the necessary administrative procedures. In this case, planning constraints prevent the full deployment volume, and careful attention is required for future process to ensure the necessary project volume will receive approval. Transparent and credible information of this kind can help private sector investors to anticipate future demand and market opportunities, and can focus government attention to address remaining uncertainties.

Figure 8. The role of forward looking, quantitative policy indicators.



A set of quantitative policy indicators can therefore increase the visibility of policy for all actors involved in renewables deployment: producers can observe that the level of future demand for their technology is supported by an effective policy framework.

First, project developers can trust the policy framework that is in place to create demand for renewable projects. Second, policy makers and governments can verify whether they have implemented the appropriate policy framework, and can manage any subsequent changes required to 'free up' the project pipeline. Third, the public can observe whether their government has implemented the necessary national policy framework and hold their government accountable to the commitments of heads of State, European Parliament, and European Commission to deliver 20% of European energy from renewables.

The quantitative policy indicators are only meaningful if they reflect a shared understanding of the policy framework and its impacts on project investments. This shared understanding does not yet exist, because so far comprehensive quantification of the individual aspects of the policy framework are not yet common-place.

Several methods, which require further development, can be envisaged to provide quantitative estimates for the different indicators. A survey among stakeholders offers one opportunity; this could provide an initial 'estimate' as a basis for further discussion with major stakeholders for renewable deployment. Such a survey would reveal where stakeholders differ in their assessment; outlining potential factual misperceptions or unforeseen policy impacts.

5. Conclusion

The European Renewables Directive requires Member States to deliver on average 20% of their final energy consumption by 2020 using renewable energy sources. To deliver this target, Member States have to adjust planning procedures, evaluate energy market design, provide grid and supply infrastructure, and implement support schemes that limit regulatory risk for finance. A failure to pursue any one of these changes risks the successful deployment of renewables.

The chapter argues for the use of quantitative policy indicators to measure the success of current and future policies. Such indicators should allow for the assessment of different policies and regulatory changes required to provide a robust framework for renewables deployment. Increased transparency provided by policy indicators facilitates management of policy implementation, enhances accountability of governments, and can inform the reporting of Member States to the European Commission. This allows technology companies to have confidence in projected deployment levels and can trigger private sector investment in the supply chain to provide the necessary production capacity.

The European Renewables Directive requires that the European Commission provides a guidance note to the Member States for their reporting in National Action Plans. This document might be a suitable location to specify quantitative policy indicators, in order to create a harmonised European approach that facilitates cross-country comparison and learning.

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The European Emissions Trading System in Belgium[1]

Johan Eyckmans and Sandra Rousseau
HUBrussel & K.U.Leuven, Centrum voor Economische Studiën

1 The authors gratefully acknowledge the meticulous data work by Yo De Groote (HUBrussel).

1. Introduction

In January 2005, the European emissions trading scheme (EU ETS in the sequel) for carbon dioxide was launched. This system is the biggest tradable emission permit scheme in the world covering almost 11.000 installations, 50% of all CO_2 emissions and 40% of all greenhouse gas emissions originating in the EU. The ETS is a cap-and-trade system under which installations are initially assigned an absolute amount of emission permits, but these allowances can be traded freely. ETS is considered by the European Commission as an essential part of its climate action plan. It should help the EU to achieve its overall greenhouse gas reduction target of minus 8% by 2020 compared to 1990 emission levels in a cost effective way, see EU Commission (2008a).

The EU ETS should be clearly distinguished from the flexible mechanisms (emissions trading ET, joint implementation JI and clean development mechanism CDM)[2] included in the 1997 Kyoto Protocol. Firstly, the European system deals with trading between firms and installations, while the Kyoto flexible mechanisms allow trading of greenhouse gas emission permits between countries. Secondly, the EU ETS scheme is limited to emissions of carbon dioxide only whereas the Kyoto system covers six greenhouse gases. Thirdly, the EU ETS started already in 2005, thus predating the start of the first commitment period of the Kyoto protocol (2008-2012). Although they are markedly different in setup, a formal link exists between both systems as certified emission reductions (CERs in the Kyoto jargon) can be used by European firms to cover their positions in the EU ETS. However, access to these CERs in the EU ETS system is limited deliberately to avoid that the EU market would be flooded by cheap CERs, see EU Commission (2008a).

The overall aim of this chapter is to investigate how EU ETS allowances were allocated to individual installations in Belgium and its main regions Flanders, Wallonia and Brussels-Capital region.[3] We will compare allocations and verified, i.e. actual, emissions[4] for Phase 1 (2005-2007) and for the first year of Phase 2 (2008). We are especially interested in observing the underlying distribution of activities and economic sectors responsible for CO_2 emissions in Belgium and covered by the EU ETS directive.

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2 For a definition of these instruments, see the item 'Kyoto Protocol' at: http://unfccc.int/.

3 Flanders refers to the northern part of Belgium and counts approximately 6 million inhabitants. Wallonia is situated in the south of Belgium and has 3.4 million inhabitants. The Brussels-Capital Region consists of the city of Brussels and its surrounding municipalities which count about one million inhabitants.

4 It should be noted that certified emissions will closely match actual emissions because of strict compliance provisions: accurate monitoring, substantial penalties and low probability of measuring errors.

Contrary to many previous studies, for instance by Ellerman and Buchner (2006) and Kettner et al. (2007), we are able to link the emissions data with company accounting data. This allows us to investigate the relation between a company's allocation gap (i.e. difference between allowances and verified emissions) and its business characteristics such as turnover, value added and profit margins. A similar analysis was made for Belgium for the years 2005 and 2006 but using aggregated data on sector level instead of individual company data, see De Bruyckere and Voorspools (2007). Our analysis is also related to the empirical work by Anger et al. (2008). Whereas the latter focus in particular on lobbying to explain the allocation of EU ETS allowances to German firms, our analysis is mainly descriptive.

Most studies hereto were limited in scope to the first trading years 2005 and 2006 of Phase 1. Ellerman and Buchner (2008) and Kettner et al. (2007) comment on the amount of over-allocation and likely abatement efforts that have taken place in 2005 and 2006. We however, will investigate the complete first phase (2005-2007) of the EU ETS in Belgium. This allows us to look at the overall picture for the first phase including the issue of 'banking'.

This chapter is organized as follows. In section 2 we provide some background information on the design of the national allocation plan in Belgium. Next, in section 3, the emissions and allocations for Belgium and its regions are discussed in general terms. Installation data concerning the first phase of the EU ETS are discussed in section 4. First we compare the allocations and emissions in the different regions. Next, installation data are analyzed based on CITL activity codes and finally, company level data are composed in order to include economic performance indicators. Section 5 concludes.

2. Background on the Belgian National Allocation Plan

Under the EU emissions trading directive 2003/87/EC (EU Commission 2003), each member state had to submit to the EU Commission so-called National Allocation Plans (NAPs) in which it specifies allocations of CO_2 allowances for all installations covered by the directive on its territory. The EU Commission had to approve this NAP before actual allocations of permits to installations could start. Two waves of NAP drafting and revision were organized, one for Phase 1 (2005-2007) and one for Phase 2 (2008-2012). The EU Commission's main criterion for evaluating the draft NAPs was whether they were consistent with a pathway to meet the member state's Kyoto target. Different from most other member states, the Belgian NAP actually consists of three regional plans. The integration of these three plans into a national plan reflects the fact that Belgium is a federal state with three different regions

(Flanders, Wallonia and Brussels Capital region) and that the bulk of environmental policy competences have been assigned to the regional authorities. In Belgium, about 310 installations are covered by the EU ETS: 170 in Flanders, 130 in Wallonia, 10 in Brussels Capital Region and 2 under the federal regime, see Belgian NAP (2004) and (2006). Compared to other EU member states, this number of installations falls between the minimum of 19 (Luxemburg) and the maximum of over 1800 (Germany). For the first phase of the EU ETS (2005-2007), Belgium's allowances amount to approximately 2.5% of the total number of EU ETS allowances. This is comparable to Finland (approx. 2%) and Greece (approx. 3%), see EU Commission (2008a).

The Belgian national allocation plan[5] (NAP) allocates on average 62.1 Mt CO_2 annually to installations covered by the scheme over the 2005-2007 period. Emission trading under the EU ETS in Belgium covers approximately 48% of its total national greenhouse gas emissions. In general, this percentage is between 30 and 50% in other member states.

The regional allocation plans in Belgium base the number of industrial allowances on historical emissions, on efficiency factors agreed upon in sector agreements (Wallonia) or benchmarking agreements (Flanders), and assumptions about future growth. Moreover, all allowances were allocated using grandfathering (*i.e.* freely distributed) to incumbent installations in all three regions in Belgium; no allowances were auctioned.[6]

During Phase 1 of EU ETS, the allocated allowances are distributed in equal portions in 2005, 2006 and 2007 and they become invalid on 2008, May 1. Thus the validity and use of the emission rights is associated with the trading period for which they are granted. This means that borrowing (*i.e.* using future allowances to cover current emissions) and banking (*i.e.* keeping current allowances to cover future emissions) were allowed within the trading period. However, banking or borrowing of allowances between phase 1 (2005-2007) and phase 2 (2008-2012) was not allowed.

3. Analyzing the EU ETS data for Belgium

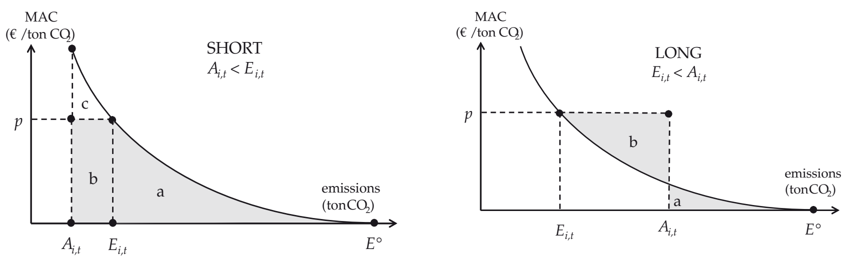
Data for the emissions and allocations (and some basic installation characteristics) were downloaded from the so-called Community Independent Transaction Log CITL database, containing information for each individual instal-

5 Sources: www.iea.org and national allocation plan (www.klimaat.be).

6 Rights allocated to installations that go out of business during the trading period are added to the reserve. This reserve is used in order to allocate rights to new firms. The reference year(s) used in the NAP 2005-2007 to forecast energy use and emissions was 2000-2001 and for the NAP 2008-2012 is 2005.

lation under the EU ETS.[7] We adopt the following terminology when talking about allocations. When the number of allowances allocated to an installation (denoted $A_{i,t}$) exceeds the number of verified emissions (denoted $E_{i,t}$) in a particular period, this installation is said to be 'long'. Installations in the opposite situation, *i.e.* when actual emissions exceed allocated allowances, are said to be 'short'. As is shown in every textbook on environmental economics (see for instance Kolstad, 2000, or Proost and Rousseau, 2007), profit maximizing firms should reduce their emissions up to the point where marginal emission abatement costs are exactly equal to the market price of a permit. If the resulting net emissions fall short of the allocated amount of allowances (i.e. when the firm is short, see left hand panel of Figure 1), they should fulfil their obligations by buying additional permits. This is cheaper than reducing their emissions below $E_{i,t}$. Every additional ton of emission reduction would be more expensive than the market price of an emission permit. In the other case, when net emissions exceed the allocated amount of allowances (i.e. when the firm is long, see right hand panel of Figure 1), it is profitable for firms to push emissions down below $A_{i,t}$. This frees up emission permits that can be sold in the market at a price higher than the marginal emission abatement cost. Hence, whether companies are short or long, they should always reduce emissions until the marginal cost of the last ton of CO_2 abated equals the market price of allowances. This is illustrated in the graph below (Figure 1). Emissions without reduction efforts (so-called business-as-usual emissions) are denoted by $E°$. Firms that are short can save costs (area c) buying permits instead of reducing in house. Firms that are long can make money (area b) on reducing their emissions more than required by the initial allowance allocation.

Figure 1: short and long allocation



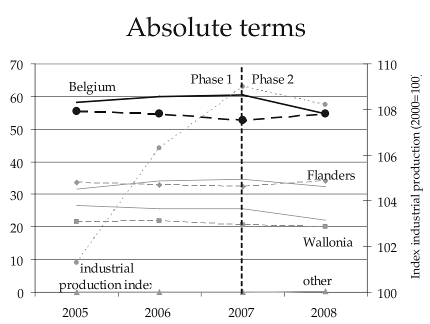
7 See: http://ec.europa.eu/environment/climat/emission/citl_en.htm. Starting from the raw data we kept only those observations for which emissions and allocation data were available for all three years of Phase 1. Due to this data cleaning, the numbers presented in this chapter can differ slightly from the numbers in official publications.

Note that the data we have available only include information on verified emissions, that is $E_{i,t}$, and permit allowances, that is $A_{i,t}$. No information is available on business-as-usual emissions $E°$ and hence, it is a priori impossible to estimate the emission abatement effort (*i.e.* $R_{i,t} = E° - E_{i,t}$), that companies have undertaken under the EU ETS. Estimating abatement efforts requires additional information sources and assumptions. See Delarue et al. (2008) for an example for the power sector under EU ETS, and Ellerman and Buchner (2008) for a discussion on how much abatement EU ETS would have delivered in its first two years 2005 and 2006.

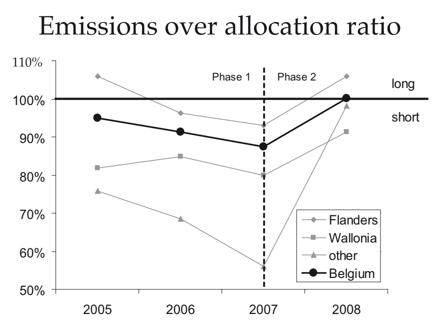
In general, we will use to the more neutral wording 'long' or 'short' as defined higher, rather than the more normative terminology 'over' and 'under'allocated. Ellerman and Buchner (2008) point out that a long (short) position is not necessarily evidence of strong (weak) emission abatement efforts. A long (short) position can be explained as well by the a priori uncertainty concerning economic activity and by stochastic disturbances (like weather conditions) that were not foreseeable when allocation plans are approved. Hence, long and short positions should never be interpreted as indications of emission abatement effort, or the lack of it.

We start by taking a look in Figure 2 at the evolution through time of emissions and allocation for Belgium and its regions. All three years of Phase 1 plus 2008 data were included.

Figure 2: Evolution of emissions and allocations for Belgium and its regions



Total number of allowances (solid lines) and emissions (dotted lines) in million tons of CO_2. Industrial production index (2000 = 100, dotted line) on right hand axis. Own calculations based on CILT data.



Ratio $E_{i,t}/A_{i,t}$ in percentage. Own calculations based on CILT data.

The left hand panel of Figure 2 shows the evolution of aggregate emissions and allocations for Belgium as a whole and for its regions. The solid lines stand for the number of allocated permits, the dotted line for the verified emissions. We aggregated data for the small number of installations under the authority of the Brussels Capital region and Federal government into one category “other”. This category’s share in overall Belgian emissions is marginal (0.1% share in aggregated 2005-2007 emissions) compared to the other regions (60.7% for Flanders and 39.2% for Wallonia). The resulting lines for this category can therefore hardly be distinguished from the x-axis. Walloon industry had a long position in every of the four years considered. Flemish installations were allocated short in 2005 and 2008, but long in 2006 and 2007.

Overall, Belgian installations were substantially long in all three years of Phase 1 (2005-2007), but were almost even in the year 2008 (Phase 2). The number of allocated emissions is decreasing while moving from Phase 1 to Phase 2 whereas emissions follow the opposite trend, especially in Flanders. This emissions trend reversal is not a structural phenomenon but it is probably caused by slight changes in definitions of variables[8] and in the composition of the dataset. The right axis of the left hand panel in Figure 2 refers to a composite index of industrial production output (physical quantities) for the Belgian economy as a whole. Remarkably, the emissions trend is the reverse of the trend in industrial production. During Phase 1, production grew continuously whereas emissions went down slightly. Moving to Phase 2, emissions went up whereas industrial production declined substantially. There are no indications in the emissions data of the economic slowdown that started in the last months of 2008. The reason emissions do not follow production could be that during the initial period of the world economy’s slowdown, production firms did not cut production but accumulated stocks. In addition, the slight redefinition of emissions (broader scope) is responsible partly for the rise in verified emissions. However, the effects of the sharp decrease in economic production due to the worldwide economic crisis will surely be reflected in 2009 emission data.

The right hand panel of Figure 2 depicts the evolution of the aggregated emissions over allocation ratios for the different regions and Belgium. If this ratio is less (more) than 100%, installations have on aggregate more (less) allowances than verified emissions, and hence they are long (short). Most regions are in most years long. The Brussels region follows a very different path from Flanders and Wallonia in Phase 1 but, as said before, its share in total Belgian

8 For instance, in Phase 2, starting in 2008; emissions of nitrous oxide from the production of nitric acid are also included in the EU ETS. Some chemical installations therefore show an substantial increase in both allocation and emissions between Phase 1 and 2 whereas this only reflects changes in emission accounting rules, see EU Commission (2008a).

emissions is negligible. For the first year of Phase 3, the Brussels' emission to allocation ratio converges to the Belgian average. All regions' emissions to allocation ratios increase strongly and converge while entering Phase 2 of EU ETS.4. Analyzing installation data for Belgium and its regions

First, we look at differences in allocations and emissions at regional level. Next, we analyze data at installation level for different activities and finally, we compose company level data in order to include economic performance indicators.

4.1 Analysis at regional level

In Table 1, we first consider aggregate allocations and emission levels for the first phase of EU ETS, i.e. the period 2005-2007. Overall, Belgian installations were allocated 59.56 million tons of CO_2 per year whereas they only emitted 54.31 million tons of CO_2. Hence, the allocation for Belgium as a whole was long by about 5.25 million tons which represents 8.8% of the total number of permits allocated. The analysis performed by Ellerman and Buchner (2008) and Kettner et al. (2007) allows us to compare Belgium with other EU member states for the period 2005-2006. Only 6 out of 24 member state had a short position. For Belgium, the balance of the gross long and short positions for its installations result in a small overall net long position, which situates Belgium mid-way. Looking at the long/short positions by member states, Belgium can be categorized with the countries that are long on balance but by relatively modest amounts such as The Netherlands, Germany, Slovenia and Portugal. As mentioned by Ellerman and Buchner (2008) these modest long positions fall well with what might be expected as a result of a relative advantage in abatement or less favourable economic, meteorological or other circumstances. Moreover, Belgium seems to show a trend to increasing energy efficiency. There is thus no evidence of over-allocation by Belgium and its regions.

Table 1: Emissions, allocations, emissions over allocation ratio 2005-2008

	Flanders			Wallonia			other			Belgium		
	E	A	E/A	E	A	E/A	E	A	E/A	E	A	E/A
2005	33.58	31.68	*106.0*	21.70	26.54	*81.8*	0.07	0.10	*75.8*	55.36	58.31	*94.9*
2006	32.98	34.24	*96.3*	21.72	25.61	*84.8*	0.07	0.10	*68.5*	54.76	59.95	*91.3*
2007	32.25	34.71	*92.9*	20.48	25.61	*79.9*	0.05	0.10	*50.2*	52.78	60.42	*87.5*
	32.95	**33.55**	***98.2***	**21.299**	**25.92**	***82.2***	**0.06**	**0.10**	***64.8***	**54.31**	**59.56**	***91.2***
2008	34.22	32.31	*105.9*	20.12	22.11	*91.0*	0.33	0.34	*98.1*	54.67	54.75	*99.8*

own calculations based on CILT data

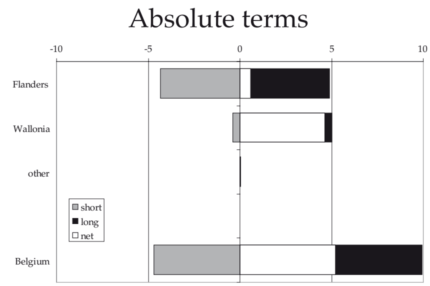
Over the entire Phase 1 (2005-2008), the *Flemish* region allocated allowances for 100.65 $MtCO_2$ to Flemish industry. This amounts to 34.72 $MtCO_2$ per year. The New Entrant Reserve (NER) was set at 0.5 $MtCO_2$ per year. The NER contains allowances that are set aside to cover emissions from firms that enter in the market. According to the *Walloon* allocation plan, the average yearly allocation between 2005 and 2007 is 25.92 $MtCO_2$ and the New Entrant Reserve amounts to 0.5 Mt CO_2. *Brussels* has allocated its installations 0.30 $MtCO_2$ over the 2005-2007 period, or an average of 0.10 $MtCO_2$ per year, and established a New Entrant Reserve of 0.009 $MtCO_2$ per year. The *federal* allocation plan deals with nuclear installations only and allocates these installations 0.00033 Mt CO_{2eq} per year (i.e. 0.001 Mt CO_{2eq} over the period 2005-2007).

Regionally, there is some marked difference. Allocations exceed emissions in all years in Wallonia and Brussels / Federal. A similar pattern can be observed for Flanders in 2006 and 2007 and for the whole of the first Phase, but its allocation fell short of emissions by 6.0% in 2005 and 7.4% in 2008 (see Table 1). Comparing Phase 1 to the first year of Phase 2, we observe that in all regions, the emission to allocation ratio increases, hence allocations are becoming tighter. In Flanders emissions exceed allocations substantially; in the other regions we observe the reverse pattern. Overall, Belgian emissions slightly exceed allocations in 2008 (see Table 1).

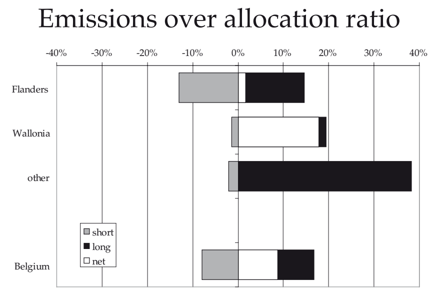
Positive net aggregate allocations (i.e. $N_r = \sum_{ier} A_i - E_i \geq 0$) in a region do not necessarily imply that all individual installations in that region are over-allocated. Therefore, we show in Figure 3, the so-called aggregate long (i.e. $L_r = \sum_{ier} \max\{A_i - E_i, 0\}$) and aggregate short (i.e. $S_r = \sum_{ier} \min\{A_i - E_i, 0\}$) positions for Phase 1. The grey bars denote total short allocations, the black bars stand for total long allocations for a region[9]. Net allocations are denoted by white bars. Flanders allocated -13.0% short and +14.6% long compared to -1.4% and +19.4% in Wallonia. Hence, Flemish environmental authorities were both stricter (i.e. allocated more installation short) and less lenient (i.e. allocated less installations long) than their Walloon counterparts.

9 What we call aggregate long or short position is labeled "gross" long or short by Ellerman and Buchner (2008), i.e. the sum of all long (short) positions of individual installations in a sector, region or country. They also speak of "net" long or short positions being the sum of gross long and short positions. We, in contrast, only speak of "net" position of a sector, region or country and the sign indicates whether it concerns a long (+) or short (-) position.

Figure 3: Average short, long and net allocations by region for Phase 1 (2005-2007



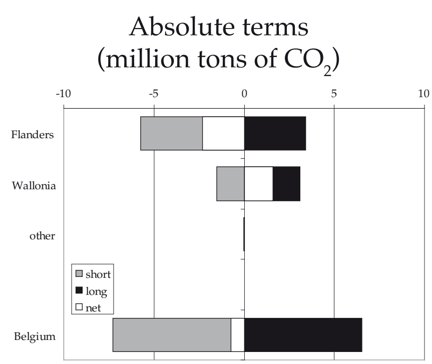
Short (grey bars), long (black bars) and net (white bars) allocations in million tons of CO_2. Own calculations based on CILT data.



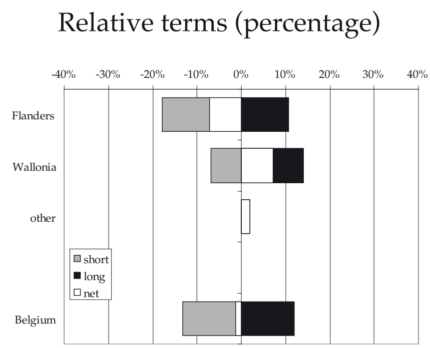
Short (grey bars), long (black bars) and net (white bars) allocations in percentage relative to total number of allowances allocated. Own calculations based on CILT data.

In Figure 4 we present a similar graph for the year 2008, the first year of Phase 2 (2008-2012) of EU ETS. The most important difference between both phases for Belgium is that in 2008, the Belgian economy as a whole was allocated short by some 1.6%. This short allocation stems from the fact that Flanders has allocated its industrial installation short in 2008 compared to long on average during Phase 1.

Figure 4: Average short, long and net allocations by region for Phase 2 (2008)



Short (grey bars), long (black bars) and net (white bars) allocations in million tons of CO_2. Own calculations based on CILT data.



Short (grey bars), long (black bars) and net (white bars) allocations in percentage relative to total number of allowances allocated. Own calculations based on CILT data

4.2 Analysis at installation level

We return now to the analysis of Phase 1. Both regions are very different in economic activity. We therefore present in Figure 5 a split of the regional emissions over different activities. The activity categories are taken from the CITL activity codes and in addition, we split the CITL Power and Heat sector into its basic components.[10] It is important to note that the regional split of emissions is based on the location of the emission source, not on the location of the final consumption of the output produced. For instance, some of the power produced in Flanders is used in Wallonia because the Belgian electricity grid is highly interconnected between the regions. Likewise, some cement produced in Wallonia is consumed in Flanders as well. Finally, it note that the CITL activity "heat" (i.e. heating boilers with a thermal capacity exceeding 20MW) covers a very wide range of economic production sectors like chemical plants, food industry, textile industry etc.

Figure 5: Average emissions by region and activity for Phase 1 (2005-2007)

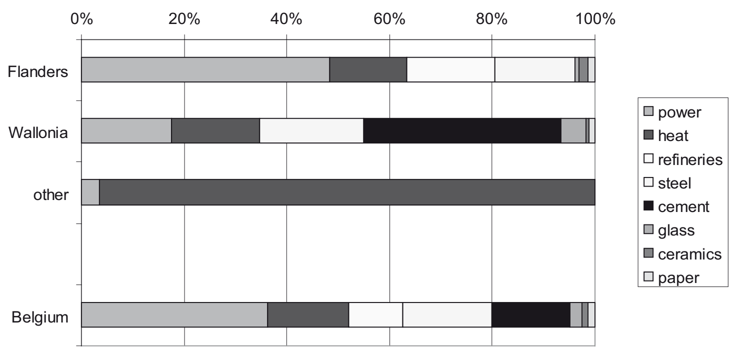
Emissions per activity in million tons of CO_2. Own calculations based on CILT data.

10 This split was done on the basis of an inventory of all power stations in Belgium.

Figure 5 reveals important differences in activities between the regions in Belgium. Flemish emissions are dominated by power producers (15 mio tons) followed by heating boilers, refineries and steel mills (each about 5 mio tons). Cement production dominates Walloon emissions (about 8 mio tons) followed by power producers, steel mills and heating boilers (each about 4 mio tons). Some sectors are exclusively located in one region: refineries are only found in Flanders, cement producers only in Wallonia. The sectors of glass, ceramics (bricks), paper and pulp are small compared to the main sources of CO_2 emissions.

In relative terms, see Figure 6, the power sector accounts for about one third of Belgian emissions, heating boilers, cement and lime production and steel mills for little more than 15% each and refineries for about 10%. In Flanders, power production accounts for 45% of regional emissions; in Wallonia cement, lime and chalk for somewhat less than 40%.

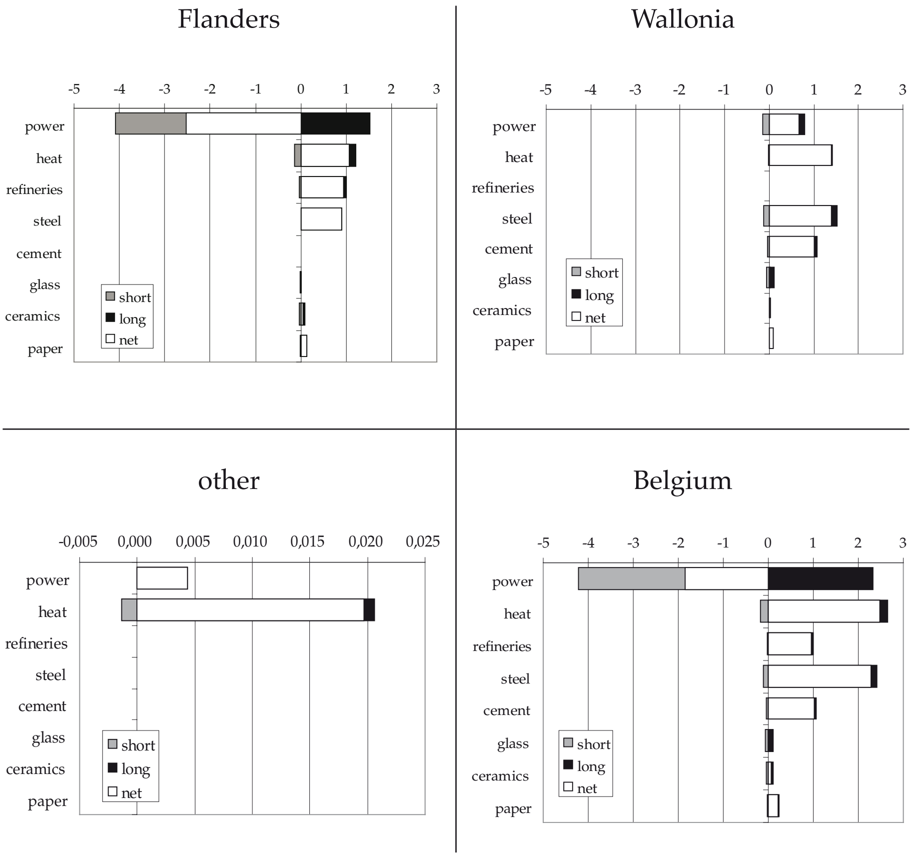
Figure 6: Emission shares by activity



Emission shares by activity in percentage of regional total emissions. Own calculations based on CILT data.

We now turn to short and long emissions by activity. Figure 7 shows that in most sectors and regions, all installations have been treated in the same way, *i.e.* mostly they have been allocated long. Only in the power sector in Flanders, we observe substantial short allocations.

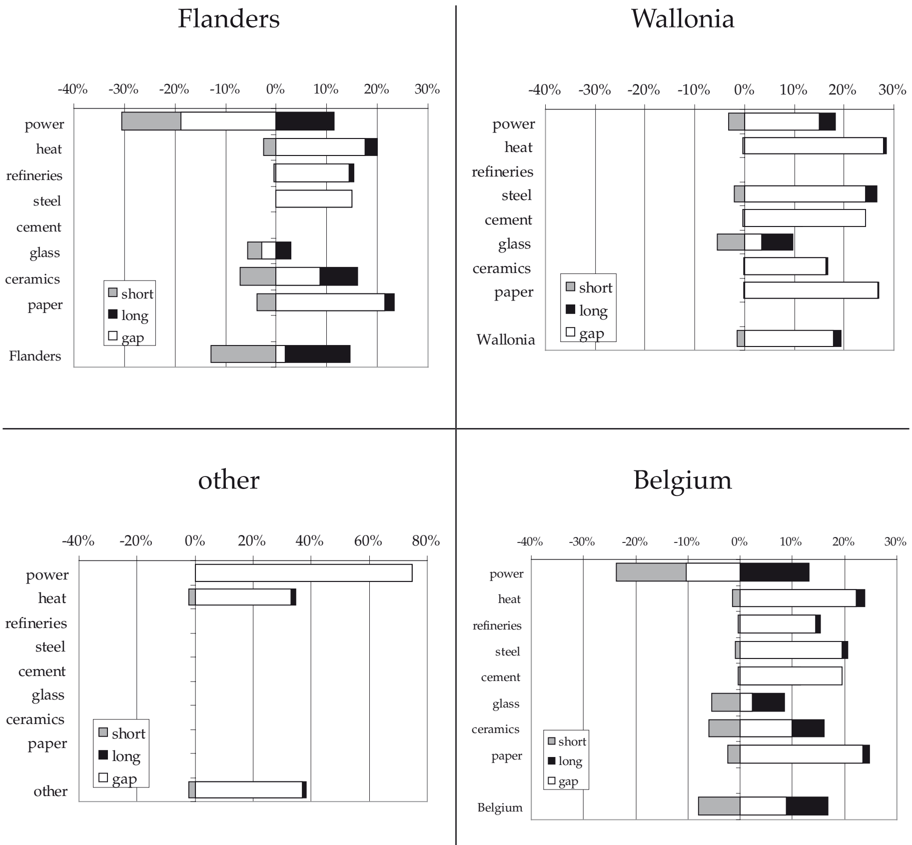
Figure 7: Average short, long and net emissions by region and activity for Phase 1 (2005-2007)



Short (grey bars), long (black bars) and net (white bars) allocations in million tons of CO_2. Own calculations based on CILT data. Mind different scale for region “other”.

According to the Belgian National Allocation Plan 2004 (Belgian NAP, 2004), the procedures to allocate emission allowances to power and heat installations are quite similar in the Flemish and the Walloon region. In both regions allocations are based on installation specific technology and CO_2 efficiency criteria. Typically, allowances are allocated with reference to a best available technology or average efficiency benchmark for the sector. For instance, for fossil fuel power stations, both regions use a combined-cycle gas turbine technology as the benchmark technology. Other technologies like for instance conventional thermal plants using coal, are assigned an amount of allowances using the CO_2 emission factor of the CCGT benchmark technology. Moreover, the regions explicitly aim at stimulating renewable energy production, fuel switching and the use of blast furnace gasses. For this reason, installations with combined heat and power as well as installations using blast furnace gasses receive a sufficient number of allowances to cover their forecasted emissions.

Figure 8: Relative short and long positions by region and activity for Phase 1 (2005-2007)



Short (grey bars), long (black bars) and net (white bars) allocations in percentage relative to total number of allowances allocated. Own calculations based on CILT data. Mind different scale for region "other".

In relative terms, see Figure 8, the most important long positions were found in the Brussels region and for installations that resort under Federal authority (see 'other' and mind the change in scale compared to the other graphs). However, given the small number and very low level of emissions of these installations, they hardly affect the overall picture for Belgium. In Flanders, heating boilers, refineries, steel mills and ceramics plants are long by about 15% and the paper industry by about 20%. The power sector is short by about 18%. The picture in Wallonia is similar, but somewhat more pronounced, for all sectors except power. Glass producers in both regions have been allocated almost exactly the amount of permits they need to cover their emissions. Only the power sector is really different since it is allocated long by almost 15% in Wallonia versus short by almost 18% in Flanders.

Zooming in on the power sector

Looking at the allocation procedure for the power and heat installations[11], we find that typically the amount of allowances allocated is equal to the forecasted emissions from heat or energy production *(FE_i)* multiplied by a benchmark emission correction factor *(c_i)*:

$$A_i = c_i FE_i$$

The correction factor c_i represents the relative position of the production technology used in installation *i* compared to the benchmark technology. For power generation, all installations using CCGT, combined heat and cokes or blast furnace gasses were assigned a correction factor equal to one. Conventional power plants (like coal fired installations) were facing a correction factor significantly higher than one. The use of this benchmarking technique implies that, if there is heterogeneity of technologies used in the power sector, this should result in some installations being allocated their verified emissions (the CCGT installations), and some others being allocated short (the less efficient installations like coal powered plants for instance). We now check in the data whether final allocations of allowances reflect this logic of the NAP.

In Figure 9, we therefore zoom in on the power sector and distinguish between different technologies. For STAG power plants, emissions over allocation ratios are very close to unity meaning that they are allocated almost exactly the amount of permits they need to cover their emissions. Conventional plants, using for instance coal, are under-allocated in Flanders but over-allocated in Wallonia. Power plants burning flue gasses from blast furnaces or cokes ovens are slightly under-allocated in Flanders and slightly over-allocated in Wallonia. Here some important caveats are to be made. First, most of these plants use a mix of fuels (also gas, coal and biomass) and therefore their net position also depends on the precise fuel mix. Secondly, for the Walloon region, no information is available on the exact amount of permits that were transmitted for free by the steel companies to the power generators upon delivery of their flue gasses. We made an ad hoc correction but probably this correction assigns too many allowances to the power generators.[12] Peak units are strongly under-allocated in Flanders, over-allocated in Wallonia and strongly over-allocated

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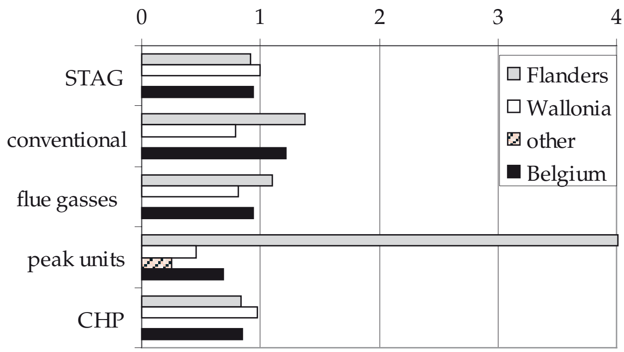
11 The federal government (not the regions) are responsible for the nuclear plants in Belgium (Doel and Tihange). These nuclear power plants emit a minor amount of CO_2 during periodic testing. In order to guarantee safety at those plants a sufficient amount of rights are allocated to cover these limited emissions.

12 A correction was made to account for flue gases from blast furnaces and cokes production that are used in power plants. According to the Belgian NAP, emission allowanes for these gases are allocated to the steel companies, but are to be transferred for free to the power companies upon delivery of the gases. For Flanders, exact corrections could be made based on detailed data disclosed publicly by the Flemish environmental administration. For Wallonia, these data are not publicly available.

in Brussels. It is important to know that the total volumes of emissions for this type of technology are very small. Combined heat power installations are slightly over-allocated in Flanders. In Wallonia they were given an amount of allowances matching very closely their verified emissions.

Figure 9: Emission over allocation ratios for power sector by technology



Own calculations based on CILT data.

It seems to us that the logic of the national allocation plans is reflected quite well in the data for Flemish installations but less so in Wallonia. This regional difference could point to a more fundamental problem in the allocation process. Not the benchmarking factors are the problem but rather the inaccurate emission forecasts. For many companies, production volumes were estimated by extrapolating past growth paths into the future. This procedure proved too optimistic in many cases. This observation points to the extreme importance of getting the emission forecasts right, if the ETS is to have the desired effect on emission levels. Note that the present – unpredicted - decrease in industrial production will therefore lead to a likely long position for most industrial sectors in 2009. Thus, we can conclude that the presence of both short and long positions in the Flemish and Walloon power sector as well as in the Flemish heat sector reflect installation specific differences and inaccurate emission forecasts rather than real procedural differences.

4.3 Analysis at company level

The link between EU ETS installations and companies is not one-to-one. A substantial number of companies in the database own more than one installation and sometimes these installations are situated in both regions. Since we want to relate emissions and allocations of companies to their economic performance in this section, we have to aggregate the installation data at the company level. The distinction between the regions becomes irrelevant in that case. For that purpose, we traced the corresponding company owning it for every installation.[13] Based on their unique VAT number, we retrieved basic economic performance indicators from the BELFIRST company accounts database, BELFIRST (2009). The indicators used in this chapter are: staff (i.e. number of employees in full time equivalent units), turnover, value added and after tax profits (EBT, *i.e.* earnings before taxes). We computed the three year averages for the first phase of EU ETS 2005-2007. The BELFIRST database classifies every company's main economic activity according to the 4-digit NACE-BEL2008 sector classification of the Belgian Federal Ministry of Economic Affairs.[14] Based on these NACE-BEL2008 codes, we aggregated companies into 14 main economic sectors. In Table 2, we report basic indicators, aggregated on that sector level. The advantage of this sector classification over the installation codes used before is that we are able to disentangle the CILT sector 'heat' into several subsectors like food & beverages, textile, refinery, chemical, nonferrous and equipment sector.

13 This was possible using installation identifier codes used in the Belgian National Registry of EU ETS installations. Sometimes, finding the matching firm proved difficult because some companies have split up their activities into different independent business units and it is not always clear to what business unit a particular installation is linked. However, we were able to link the vast majority of installations and for the remainder of the analysis we ignore observations for which the link could not be made with certainty.

14 See http://www.belgostat.be for the sector classification details.

Table 2: Accounting data by sector

	staff		turnover		value added		profits		profit margin
	FTE	%	million €	%	million €	%	million €	%	%
extraction	1,048	0.7	403	0.4	164	0.8	7	0.1	1.8
food & beverages	14,709	9.8	7,863	7.8	1,907	8.8	880	11.6	11.2
textile	71,56	4.8	1,224	1.2	349	1.6	-16	-0.2	-1.3
wood, pulp & paper	4,259	2.8	2,008	2.0	643	3.0	132	1.7	6.6
refinery	4,172	2.8	23,672	23.4	1,655	7.6	2,371	31.3	10.0
chemical	32,385	21.5	18,874	18.6	7,167	33.0	1,676	22.1	8.9
glass	5,312	3.5	1,338	1.3	501	2.3	54	0.7	4.0
bricks & building materials	3,197	2.1	799	0.8	288	1.3	49	0.6	6.1
cement	1,529	1.0	667	0.7	304	1.4	111	1.5	16.6
steel	15,878	10.5	9,069	9.0	2,076	9.5	618	8.2	6.8
nonferrous	9,087	6.0	6,848	6.8	898	4.1	241	3.2	3.5
engineering & equipment	37,823	25.1	14,761	14.6	3,245	14.9	416	5.5	2.8
power	9,037	6.0	12,779	12.6	2,073	9.5	977	12.9	7.6
other	4,987	3.3	928	0.9	478	2.2	65	0.9	7.0
TOTAL	**150,581**	**100.0**	**101,231**	**100.0**	**21,748**	**100.0**	**7,579**	**100.0**	**7.5**

Own calculations based on BELFIRST and CILT data.

We observe that over half of the workforce in the sectors included in the Belgian EU ETS is employed in the equipment, chemical and steel sectors. Next, in terms of sales revenues the largest sectors involved in the EU ETS are the refinery and chemical sectors followed by the equipment and power sector. However, in terms of value added the chemical sector is by far the most important contributor to the total Belgian value added (i.e. GDP), with the equipment sector as a second. The extraction sector has the lowest contribution to GDP. When we look at industry profits, the perilous position of the textile sector is striking. Finally, we calculated profit margins as total profits divided by sales revenues. High profit margins prevail in cement, food & beverages and refineries (>10%) industries; low profits (<3%) in extraction and equipment (including car assembly) sectors.

Table 3: Emission data by economic sector

	emissions Mt CO_2	allocation Mt CO_2	emissions over allocation %	short emissions Mt CO_2	long emissions Mt CO_2	net emissions Mt CO_2
extraction	3,155,821	3,676,392	85.8%	-2,575	539,839	520,571
food & beverages	2,049,577	2,271,192	90.2%	-106,304	321,711	221,615
textile	86,090	117,593	73.2%	-68	33,022	31,503
wood, pulp & paper	743,869	976,972	76.1%	-18,580	242,006	233,103
refinery	4,151,012	4,989,420	83.2%	-60,255	925,235	838,408
chemical	3,113,237	3,798,485	82.0%	-17,955	707,216	685,248
glass	1,351,314	1,400,729	96.5%	-72,556	131,670	49,415
bricks & building materials	641,378	704,670	91.0%	-43,306	108,115	63,291
cement	5,016,599	5,515,607	91.0%	-34,063	526,313	499,008
steel	11,362,493	15,146,586	75.0%	-118,151	3,910,325	3,784,093
nonferrous	226,734	251,578	90.1%	-5,688	30,333	24,844
engineering & equipment	233,515	315,559	74.0%	-2,294	84,387	82,044
power	19,671,462	17,377,730	113.2%	-5,105,726	2,621,817	-2,293,733
other	2,570,084	2,963,246	86.7%	-25,150	416,957	393,162
TOTAL	**54,373,185**	**59,505,759**	**91.4%**	**-5,612,671**	**10,598,946**	**5,132,572**

Own calculations based on BELFIRST and CILT data.

As was already indicated higher, Table 3 shows that only the power sector was allocated fewer allowances than its verified emissions, resulting in a negative gap for this sector. Even though all sectors include both firms with short positions and firms with long positions, the distribution of these short and long firms seems to vary over sectors. As a case in point, the extraction (limestone industry), textile, chemical and equipment sectors have few firms with short positions ('short' less than 3% of 'long').

As mentioned by Kettner et al. (2007), the sectoral differences in the generosity of allocations can be motivated by the ability to pass on additional costs due to market power and/or low price elasticity of demand, the industry's abatement costs, the share of CO_2 costs in total production costs and by the international competitiveness position of sector. The net impact of these different elements on a sector's allocation can thus be difficult to explain. In order to understand better underlying characteristics, we computed in Table 4 different ratios relating companies' emissions to their economic performance.

Table 4: ETS impact by sector

	emissions over turnover g CO_2 per €	ETS impact over turnover %	ETS impact over profit %	ETS Phase 3 impact over turnover %
extraction	7832	1,29	72,10	-31.33
food & beverages	261	0,03	0,25	-1.04
textile	70	0,03	1,91	-0.28
wood, pulp & paper	370	0,12	1,77	-1.48
refinery	175	0,04	0,35	-0.70
chemical	165	0,04	0,41	-0.66
glass	1010	0,04	0,92	-4.04
bricks & building materials	803	0,08	1,29	-3.21
cement	7526	0,75	4,50	-30.10
steel	1253	0,42	6,12	-5.01
nonferrous	33	0	0,10	-0.13
engineering & equipment	16	0,01	0,20	-0.06
power	1539	-0,18	-2,35	-6.16
other	2771	0,42	6,08	-11.08
TOTAL	**537**	**0,05**	**0,68**	**-2.15**

Own calculations based on BELFIRST and CILT data.

The first column of Table 4 reports the ratio of emissions over turnover, i.e. an indicator of intensity of the different sectors measured in gram CO_2 per € turnover. The highest emission intensity can be found in the extraction (limestone industry), cement, power and steel sectors.

The next column reports an imputed cost of CO_2 emissions trading for the first phase of EU ETS. This CO_2 cost is defined as the net long/short position times average permit price over the trade period (taken here to be 10 €/ton CO_2) divided by turnover. This cost measures only the direct trading costs (i.e. selling and buying of permits) and does not include effects on abatement costs. Thus a positive CO_2 cost implies positive rents to the sector since its firms could have sold excess allowances on the market. A negative amount, on the other hand, implies a monetary cost for the sector since it needs to buy additional permits to cover its verified emissions. Admittedly, this CO_2 cost measure is crude because (1) spot market prices of EU ETS allowances were very volatile during Phase 1 (see, among others, Alberola et al. 2008), and (2) the fact that companies holding surpluses by the end of the first phase probably did not bother selling them as the price on the spot market was almost zero. Hence, the exact cost of fulfilling its obligations under EU ETS might be higher or lower depending on the exact timing of permit exchange operations. Still, our crude measure reveals that for most sectors the impact of the trading costs associated with EU ETS is very small: on average only 0.05% of turnover, and less than 1% for almost all sectors. Only for the extraction sector this measure exceeds 1% of their turnover. Also, we find that only the power sector had to bear a financial cost which turned out to be limited: -0.18% of its turnover. It should be noted here that turnover includes the CO_2 costs that are transferred to the consumer via output price increases. Thus it is a net effect, including partial compensation of ETS related costs. Compared to profit levels, the impact is on average more pronounced: 0.68% of profits. For the extraction sector, the impact amounts to more than 70% of their profits.

Finally, we also computed a 'worst case' impact of CO_2 regulation. The 'ETS Phase 3 impact over turnover' takes into account full auctioning of allowances and is calculated as the sector's total emissions times average estimated permit price (i.e. 40€/ton CO_2 according to the impact study, see: EU Commission, 2008b). Looking at the ratio of this hypothetical CO_2-cost over revenues per sector indicates that the impact of changing from grandfathering to auctioning of permits would be huge on the trading costs incurred by the extraction and cement sectors (about 30% of sales revenues) and still sizable for steel, bricks and building materials and power sectors (between 5% and 10%). However, it is important to note that these costs would not necessarily be borne by the companies themselves since part of the trading costs will likely be transferred to the consumers. The extent to which costs can be passed on by increasing product prices will essentially depend on the price elasticity of demand which is very different for the sectors and firms in the database.

Table 5: Spread measures by sector

	Number of companies	normalized standard deviation allocations	Herfindahl index allocations	Herfindahl index emissions
extraction	4	36	2987	2972
food & beverages	33	345	917	986
textile	11	87	1281	1438
wood, pulp & paper	10	86	1530	1832
refinery	7	226	6469	6258
chemical	38	108	674	656
glass	10	123	3128	3644
bricks & building materials	15	138	1384	1520
cement	3	156	3549	3406
steel	8	44	2958	3191
nonferrous	7	82	2675	2716
engineering & equipment	20	70	1088	1003
power	4	213	6467	7339
other	34	153	4124	4848
TOTAL	*204*	*153*	*2146*	*2331*

Own calculations based on CILT data.

As illustrated before, the allocation gaps (i.e. difference between allocated allowances and verified emissions) can be quite different for firms in one sector. In order to measure the dispersion of these allocation gaps, we computed for each economic sector the standard deviation of the allocation gaps normalized by the mean allocation level of the corresponding firms. For Belgium as a whole, we observe a dispersion measure of 153%. As shown in Table 5, this dispersion indicator varies substantially over sectors. The extraction sector shows the lowest dispersion with only 36%, in contrast to the food and beverage sector with 345%. Also, the refinery and the power sector show a significantly higher dispersion than average. This dispersion is most likely linked to, (1) the number of firms in a particular sector, and (2) the heterogeneity of production processes used.

The variability of the allocation gaps within a sector might be explained in several ways. Firstly, it might relate to technical characteristics and reflect the heterogeneity or homogeneity of production techniques used in the sector. For instance, the low dispersion within the extraction and steel sectors reflect the homogeneous nature of the production processes used. For the food & beverages and power sector, the opposite holds. The high dispersion measure in the power sector is surely an indication of the underlying heterogeneity of the energy production processes. As we mentioned before, allowances in the energy sector were allocated by using the combined-cycle gas turbine as benchmark technology. Thus differences in the allocation gaps closely mirror differences in power generation technologies.

Secondly, the observed variability of the allocation gaps might be explained by lobbying activities by firms or interest groups. Anger et al. (2008) test for this hypothesis on a similar dataset of German companies. As a measure of lobbying, they use the number of employees in sectoral lobbying organizations. This type of data is, however, not readily available for Belgium. In this chapter, we therefore use an indirect measure of lobbying potential, i.e. the concentration of emission shares. The idea is that highly concentrated industries would be able to coordinate their lobbying activities more easily than highly dispersed sectors. The last columns in Table 5 report Herfindahl-Hirshmann indices (HHI) of concentration of allocation and emissions shares. The HHI for a particular sector equals the sum over all firms of their squared emission shares. If all emissions would be concentrated in only one company, HHI would equal 10.000 (100 times 100). As can be seen, concentration is particularly high in the power sector and refineries. The picture is the same for the HHI calculated using emissions or allocation numbers. In spite of its high concentration, the power sector was the only 'short' sector in Belgium. And some moderately concentrated sectors received relatively generous allocations. Hence, at first sight there seems to be no systematic relationship between industry concentration and emission over allocation ratios. This is of course no proof of absence of lobbying in the regional allocation process. Further analysis, using more accurate measures of lobbying activity by sectors, is required to answer this question.

5. Conclusions and suggestions for further research

The purpose of this chapter was to analyze the allocation to installations of allowances for the first phase (2005-2007) of the EU ETS in Belgium. Interesting about Belgium is that its National Allocation Plan is the sum of three different regional allocation plans because environmental policy has to a large extent been regionalized. The data shows that overall Belgian installations have been allocated long, i.e. have been given more allowances than what they need to cover their verified emissions, during all years of Phase 1. Taken together over all years of Phase 1, the gap between allocations and emissions amounts to almost 9% for Belgium. In Flanders, the allocation was short in 2005 but long by about 2% in total for the three years of Phase 1. Walloon industry was long by 8%, Brussels installations even by 33% (but their share in total Belgian emissions is less than 1%). When moving to Phase 2, a trend reversal seems to have happened. For the first year of the second phase (2008), the number of allowances is almost equal to verified emissions and emission to allocation ratios increase strongly for all regions. For Phase 2, Flemish allocations were short by 6%, Walloon allocations long by 9%, and Brussels' allocations long by 2%.

Looking at different activities, we see that in particular the power sector in Flanders was allocated short. This is in line with the allocation formulas in the regional allocation plans that use emission intensity of a combined cycle gas turbine plant as a benchmark to allocate allowances. For the Walloon region, we find, surprisingly, that conventional power plants (using for instance coal) have been allocated more generously than the benchmark. This is probably due to substantial overestimation of the production volume forecasts that enter the allocation formula.

A major innovation of this chapter over previous studies is that we were able to link individual installations to the companies owning them and hence, also to economic performance indicators. The analysis shows that for most sectors, the impact of EU ETS on their profitability has been very limited, and mostly non negative, during Phase 1. Only the extraction sector (lime production) might have generated substantial revenues from selling surplus allowances. Smaller revenues are likely in the steel and cement industry. However, much depends on the timing of their allowance sales decision. If they banked surplus allowances, they were not able to make profits because by the end of Phase 1, the EU allowance price collapsed. We also did a hypothetical exercise in which we assumed that companies had to buy permits at the price of 40€/ton CO_2 for each ton of their verified emissions. This corresponds to the auctioning mechanism proposed for Phase 3 (2012-2020) of EU-ETS. This analysis reveals potentially important impacts for extraction and cement industry up to 30% of their turnover if they would not be able to recover part of the CO_2 cost via an increase of their output prices.

Overall, it seems that the EU ETS is unlikely to have a significant effect on the Belgian installations' abatement efforts. A notable exception is the power production sector where fuel switching as a result of changes in relative prices of fuels, has probably lead to significant emission abatement as argued by Delarue et al. (2008). This is hardly surprising given the CO_2 allowance price collapse in 2006 and the relatively short time that elapsed since the introduction of EU ETS. However, the presence of the emission trading system has lead to an increased awareness of the climate problem, both at industry level and individual citizen level. The real impact of the EU ETS depends largely on expectations concerning the future auctioning of allowances, the expected overall tightening of climate policies, future permit prices and forecasts of economic activity.

Further research into the underlying factors influencing the allocation of CO_2 allowances in Belgium would be useful as well as a comparison to other countries. In particular the political economy of the distribution of allowances to sectors and individual companies remains an interesting research topic.

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Is There a Future for Nuclear Energy?

Johan Eyckmans and Guido Pepermans
HUBrussel & K.U.Leuven, Centrum voor Economische Studiën

1. Introduction

This contribution discusses the role of nuclear power in the future energy system. During the last decade, a number of – mainly European – countries took the political decision to phase-out nuclear power for the production of electricity, but many of them are considering to revise this decision. This contribution discusses whether, from an economic perspective, it would be wise to ban the use of nuclear power for electricity production. We review the traditional arguments for government intervention in the electricity market in general and apply them to nuclear technology.

We believe that a review of the arguments is necessary because the current debate is strongly polarized between opponents and advocates of nuclear energy. We therefore hope that our review can contribute to an open and informed public debate. Readers looking for a clear yes or no answer will probably be disappointed with this contribution. At several instances, we will sketch advantages and disadvantages of particular policy options, but often it is impossible to make robust recommendations because, among others, adequate data are missing or because normative arguments are involved for which science cannot give clear cut guidance.

Issues of market power in the electricity market, external costs of power generation technologies and security of supply will be the main focus of our review. All of these argument call for some form of government intervention because unregulated markets would yield undesirable outcomes from a societal point of view. But the main question is how, and to what degree, public authorities should intervene in electricity markets?

We will show that tradeoffs need to be made. Basically, low consumer prices of electricity, ambitious future greenhouse gas emission reduction targets and a complete ban on the use of nuclear energy for electricity generation are incompatible. If a nuclear phase-out is the policy choice of the government, then it should accept the consequences in terms of an increased cost of the energy system. Nuclear capacity will have to be replaced by other, likely more expensive technologies with their own externality problems, which will increase the cost of the energy system and thus also electricity prices.

We will also argue that technology bans are seldom wise from an economic perspective. Economists believe that technology choices should be left to private investors who have an important informational advantage over public authorities. Policy makers should limit themselves to creating a framework in which all necessary conditions are fulfilled to take well informed and socially optimal decisions. However, relying on decentralized decisions of private investors is desirable only if their incentives and societal objectives are aligned.

This requires getting the prices right for the use of all technologies, taking into account all relevant external costs by means of, for instance, emission taxes or tradable permits, or contributions to decommissioning and nuclear waste management funds.

The contribution is structured as follows. Section 2 gives a short overview of nuclear generation capacity and production. The aim is to put the contribution of nuclear energy to the World's energy provision in perspective. Section 3 discusses the role of governments and policy makers in the technology choice process. To streamline the discussion, we first discuss whether, and if yes how, direct government intervention in generation technology choices should look like. In section 4, we apply these insights to nuclear power and discuss the advantages and disadvantages of the nuclear technology. We will focus mainly on externalities and security of supply arguments. Section 5 argues that low electricity prices are incompatible with an energy system in which nuclear energy is phased-out and emissions of greenhouse gases are strictly capped. This latter point is illustrated with some simulation exercises for Belgium and for the World as a whole. Finally, section 6 concludes.

2. The rise and fall and rise of nuclear energy?

Research on radioactive materials and nuclear fission technology started in the 1930ies with pioneering work by scientists like Fermi, Bohr and Hahn.[1] The research was boosted in the late 1930ies and early 1940ies by the quest for nuclear weapons during the Second World War. After the war, research into more peaceful applications of nuclear energy lead to the construction in the US and Russia of the first nuclear reactors that were able to produce electricity. The first commercial nuclear power plant was the UK reactor of Calder Hall in Sellafield which opened in 1956 and had an installed generation capacity of 50 MWe[2] (later expanded to 200MWe). Since then, many countries followed and by now, some 436 reactors are operational worldwide, see Table 1.

According to the Nuclear Energy Institute, total operational nuclear generation capacity amounted to 372 GWe in January 2009 of which 78,4% was installed in OECD countries and 21,6% in non-OECD countries (see Table 1). The United States, France, Japan, the Russian Federation and Germany are the most important countries in terms of installed nuclear generation capacity. These five countries account for about 253.6 GWe, which is 68% of worldwide capacity.

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1 See U.S. Department of Energy (2000) for a history of nuclear energy.
2 MWe: Megawatt of electricity, GWe: Gigawatt of Electricity.

However, in terms of capacity under construction and planned capacity the leading role of OECD is much less pronounced. In non-OECD countries, 77 new reactors are under construction versus 33 in OECD countries. The distribution is even more skewed if we look at planned reactors: 63 in the OECD countries versus 206 in non-OECD countries.

In terms of the share of electricity production covered by reactors, France (77%), Lithuania (64.4%), Slovakia (54%), Belgium (54%) and Ukraine (48%) are in the top 5. In 2008, 16 countries relied on nuclear power for more than 25% of their electricity production (NEA (2008)). On a worldwide scale, nuclear plants provide about 16% of electricity production. In OECD-countries, about 23% of electricity is produced with nuclear plants. Of total primary energy consumption (which includes, besides electricity, fuels for heating, transport, …), the share of nuclear energy is about 5% according to BP (2009).

The weighted average age of the operational nuclear plants is slightly above 25 years, with the oldest plants being 42 years old. Figure 1 shows that the growth of installed nuclear capacity has slowed down over the past 15 to 20 years, in the aftermath of the nuclear accidents of Three Mile Island (1979) and Chernobyl (1986) and the collapse of fossil fuel prices in the mid eighties. Over the past 15 years, between 2 and 6 reactors per years were added, whereas in earlier years the annual increase was higher. Confronting these numbers with the data in Table 1, and assuming an average construction lag of about 60 months, suggests that this slowdown is coming to an end as 43 nuclear plants are currently under construction. In the medium to long run, we see in Table 1 that a further 110 reactors with a total capacity of 121 GW are planned and that 267 nuclear reactors have been proposed of which 32 in Europe. Overall, these data suggest that nuclear power is experiencing a revival compared to the past 15 to 20 years.

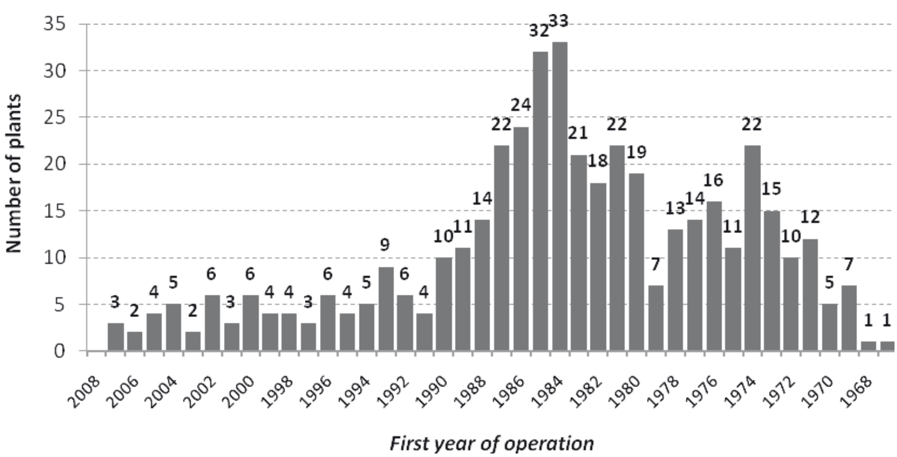
Table 1: Worldwide nuclear installations and capacity in 2009

	Nuclear Electricity Generation (2007)	Reactors Operable		Reactors Under Construction		Reactors Planned[1]		Reactors Proposed[2]		Uranium Required 2009
	TWh	*No.*	*GWe*	*No.*	*GWe*	*No.*	*GWe*	*No.*	*GWe*	*tonnes*
OECD	**2,187.9**	**341**	**309.2**	**13**	**13.2**	**33**	**42.7**	**63**	**89.6**	**54,626.0**
OECD America	904.8	124	114.8	2	1.5	15	18.3	28	34.6	20,779.0
OECD Europe	879.5	144	130.4	4	4.1	2	2.4	32	51.0	22,015.0
OECD Pacific	403.6	73	64.0	7	7.6	16	22.0	3	4.0	11,832.0
Non-OECD	**420.3**	**95**	**62.7**	**30**	**24.5**	**77**	**78.4**	**204**	**174.3**	**10,879.0**
Total	***2,608.1***	***436***	***371.9***	***43***	***37.7***	***110***	***121.1***	***267***	***263.9***	***65,505.0***

[1] Planned: firm decision
[2] Proposed: under consideration.
Source: NEA (2008)

Focusing on Europe however, we observe in Table 1 that four reactors are under construction, while only two new reactors are planned. In the recent past, Belgium, Germany, the Netherlands, Spain and Sweden have announced to reduce their dependence on nuclear power, via a gradual phase-out policy. In Germany, the shutdown date for the last reactor is 2022. In Sweden, the last nuclear plant would close in 2025, in the Netherlands in 2033. In short, Europe does not appear to follow the trend sketched above. However, recently some countries (Belgium, Sweden and Germany) are reconsidering their phase-out decision while others are planning (Ukraine, the Russian Federation, the United Kingdom) or considering (Italy, Poland, United Kingdom) to build new reactors.

Figure 1: Age structure of nuclear plants



Source: NEA (2008).

To be complete, it should be noted that some reactors have already been closed in the past. The first reactor was closed in 1968 and over the past decades, a total of 128 nuclear plants have been taken out of service with a total capacity of about 40 MWe. Most of them were test reactors that had been build for scientific research purposes.

In Belgium, seven reactors were build between 1974 and 1985, see Table 2. The oldest three of these reactors date back to 1974 and 1975 meaning that their 40 year operating license is due to expire in 2014 and 2015. They represent about 1,800 MWe or 31% of total installed capacity in Belgium. Recently, the Belgian government has proposed to extend the lifetime of these installations to 2025. As of today (June 2010), a final decision has not been approved by the Belgian Parliament.

Table 2: Nuclear reactors in Belgium

	Installed capacity (MWe)	Starting year of operations	Year of decommissioning (40 years lifetime)	Proposed Extension of lifetime
Doel 1	392.5	1974	2014	2025
Doel 2	433.0	1975	2015	2025
Doel 3	1,006.0	1982	2022	
Doel 4	1,008.0	1985	2025	
Tihange 1	962.0	1975	2015	2025
Tihange 2	1,008.0	1982	2022	
Tihange 3	1,015.0	1985	2025	
Total	**5,825.5**			

Source: Devogelaer and Gusbin (2009).

3. Why should the government intervene in the electricity sector?

In this section we focus on the question whether policy makers should actually impose on the electricity generation sector what technology (not) to use. We think good reasons exist to leave technology choices – i.e. whether or not to use nuclear – to the private sector. However, this is not the same as arguing that a government has no role to play in *steering* the technology choices made by electricity generation firms, as economic textbooks tell that government intervention can enhance social welfare when market failures exist.

3.1 Market power

With respect to the electricity sector, several types of market failures can be identified. The first one is market power, which refers to situations where firms have an advantage over other producers due to economies of scale or scope, the availability of information, access to specific resources or technologies, or because they are protected by law. Under conditions of market power, profit maximizing firms will typically restrict their output in order to raise the price for their product and to generate more profits for themselves. This reduces social welfare compared to the social optimum because some consumers with marginal willingness to pay higher than the marginal production cost will not be served. Moreover, the high price leads to a transfer of surplus from consumers to the producer. In this situation, welfare can be improved by means of appropriate public regulation in order to make the firms with market power behave more in line with efficient and socially desirable market outcomes.

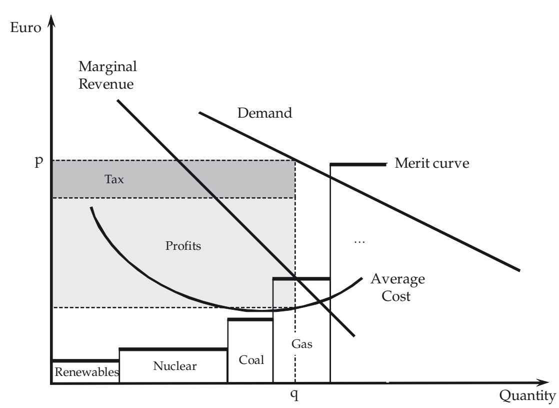
Theoretically, the high investment costs in nuclear or conventional power plants constitute a barrier to entry for potential newcomers that want to challenge the incumbent power producers. Moreover, demand for electricity is typically very price insensitive such that price increases do not lead to a strong decline in demand. And in spite of deregulation, the wholesale electricity markets in many geographical areas remain highly concentrated. Hence, necessary conditions for potential abuse of market power are satisfied. In practice, it is very hard to prove the abuse of market power by dominant firms in a market. But, after an extensive investigation, a report commissioned by DG Competition of the European Commission concludes: "*Ultimately, our analysis supports the two key points of the sector inquiry report; namely, that the current market structure in the EU electricity markets (the six markets studied) in a significant number of hours is likely to be conducive to anticompetitive behaviour. And secondly, that price outcomes on the EU wholesale electricity markets may have been less keen, than they otherwise would have been, had the markets been structured more competitively.*" (London Economics (2007), page 6)

The response to this problem of market power has changed over time. Initially and up to the 1980ies, public authorities relied mostly on direct regulation of electricity sales prices to limit producer's market power. Typically, prices were capped by the government and where determined by a so-called cost-plus rule that allowed power companies to cover their production and investment costs plus a "fair" return. However, during the last decades, a shift in policy was made towards promoting competition at the production and distribution side by means of market deregulation. In many countries, electricity retail, transport and power production activities were separated by splitting up the vertically integrated monopolies into independent business units.

Taxing rents of written off nuclear power stations?

In several countries, among others in Belgium, strong voices are heard pleading for taxing the profits of power producers who own old, economically written off, nuclear power stations. It is correct that these power stations are very profitable and contribute in a very substantive way to the profits of power producers. We illustrate this argument in Figure 2. In the so-called short-run merit curve, *i.e.* the ordered list of electricity generation technologies which constitutes the marginal cost curve of electricity production, nuclear energy is typically characterized by low marginal costs (height of bars) and high capacity (width of bars). In a market equilibrium (with or without market power), the sales price of electricity is determined by the marginal technology, i.e. the last and most expensive generation technology that has to be called upon to cover demand at a given time. This marginal technology is very often a gas fired power plant which is more flexible than base-load technologies like nuclear or coal fired plants. Given the typical merit curve, electricity companies owning low marginal cost plants like nuclear or wind turbines, enjoy high profit margins on these plants. For completeness, it should be added that since we are looking in Figure 2 at marginal costs, fixed investment and capital costs are not covered yet. Rents, i.e. the area between the price and the merit curve, should be sufficient to cover fixed capital costs. The average or unit cost curve in Figure 2 does take into account these fixed costs and is therefore best suited to illustrate the economic profits. The shaded area, average profit margin (i.e. price minus average costs) times production volume, depicts profits in Figure 2.

Figure 2: Short-run merit curve and electricity market outcome



Governments can very well think that this constitutes an unfair sharing of the welfare surpluses in the electricity market and therefore rents should be redistributed. A lump-sum profit tax is in that respect probably the best instrument to recapture rents from the private sector since it does not distort marginal production decisions. However, we also believe that one should take this argument further than only for nuclear energy. The same arguments can be used for other technologies, like conventional coal fired plants or off shore wind farms and, ultimately, all capital intensive installations in other industries like for instance cement kilns, steel mills, crackers in refineries and so on. Hence, we believe governments can resort to taxing rents of installations that are economically written off but we see no reason to apply the argument to nuclear energy only. Such a profit tax is illustrated in Figure 2 as well. It simply carves out part of the shaded economic profit area.

Although many issues remain to be solved and evidence is mixed whether this change in regulation has promoted social welfare, see for instance Joskow (2008), it shows that governments are actively intervening in an attempt to limit market power of electricity producers. Would a ban on the use of nuclear power solve the problem of market power in the production of electricity? The answer is clearly no. Also other power generating technologies like conventional coal fired power plants or off shore wind farms face high upfront capital costs acting as barriers to entry for newcomers. We believe that the issue of market power in electricity generation is very important in terms of social welfare, but that it should be tackled with appropriate regulation strategies. Which form this regulation should take is beyond the scope of this contribution but we are convinced that a simple ban on the use of one particular technology will not solve the problem of market power in the power sector.

3.2 Environmental externalities

A second market failure, and in the case of electricity markets one of the most important ones, is the presence of environmental externalities. Externalities refer to situations where decisions taken by one agent have an uncompensated positive or negative impact on the well-being or production possibilities of other agents. Examples of negative external effects in the electricity sector are the environmental damage caused by burning fossil fuels for electricity generation or the nuclear waste and catastrophic accident risk associated with the use of nuclear reactors. Damage is caused to those living in the immediate or wider neighbourhood (acid rain, particulate matter…), but also to present and future generations (CO_2-emissions, nuclear waste…). Without government intervention these external costs are not reflected in market prices resulting in too much use of technologies bearing negative externalities. Referring back to Figure 2, the full cost to society of producing electricity should include both the private production costs (reflected by the merit curve) and the marginal external costs. From the point of view of society, the relevant marginal cost curve for the supply of electricity is situated above the merit curve (see Figure 3). The welfare maximizing production (price) level of electricity is therefore lower (higher) than the level chosen by a perfectly competitive profit maximizing power company. In section 5, we will pursue this point and review the available estimates of external costs associated with different electricity generation technologies.

A public good is an extreme case of the presence of externalities. It is a good for which the benefit derived by one consumer does not reduce the benefit to anyone else and no consumer can be excluded from enjoying these benefits. Standard economic theory tells us that unregulated markets are unable to provide socially desirable levels of public goods because of free riding behaviour by its beneficiaries. In the context of energy markets, security of supply is a public good. Security of supply can broadly be defined as the adequate, affordable and reliable supply of energy (IEA (2007)). Markets will by themselves not correctly reflect the costs and benefits of security of supply because it is beyond the power of an individual producer or consumer to guarantee security of supply. Again, there is a role for governments to take care of an appropriate level of security of supply as this will benefit all consumers and producers. Governments have at least partially tackled the security of supply issue by developing policies with respect to adequate investments in the energy system, the efficient use of energy (mitigating demand growth), fuel mix diversity and market transparency.

In this contribution, we consider external effects and security of supply as the two major drivers for government intervention in energy markets. Both will be at the centre of the arguments that follow in the next sections.

3.3 Government intervention is desirable, but how?

Policy makers should give correct incentives to firms to produce and to consumers to consume, but the question is how to do this? Should policy makers forbid electricity generation firms to use particular technologies like coal or nuclear plants? Should it instead impose to use, or subsidize, other generation technologies such as solar photovoltaic cells and wind turbines? Or is it better to correct market prices to reflect external costs and let producers and consumers decide for themselves?

Generally speaking, the economics literature is very sceptical about using mandatory technology regulations, because of two major arguments[3]. First, firms are much better informed than policy makers when it comes to taking investments decisions. They have a better informed view on technical feasibility and on the exact investment, operational and maintenance costs of production technologies. Policy makers thus have a structural information disadvantage which could have as a consequence that expensive production technologies are prescribed or cheap technologies are forbidden.

The second argument is based on the cost implications of technology regulations as these would restrict the set of allowed production alternatives that are available to producers. In the case of electricity generation, this will result in higher electricity generation costs, or in situations where emission reduction measures are not implemented where they are cheapest.

It should therefore not be surprising that most economists are not in favour of using technology regulations, which they label as a non-market based policy instrument. They prefer using market based instruments instead. Market-based measures have as an effect that generation activities and primary resources that cause relatively larger external effects are discouraged (but not forbidden outright) compared to cleaner technologies and primary fuels.

In the context of environmental policy making, two important market based instruments exist: emission taxes and emissions trading. Both policy instruments are market based in the sense that the pricing signal for electricity is corrected such that all relevant social costs and benefits are internalized. Profit maximizing electricity producers will select a technology mix that minimizes the total cost of production and, because external effects are priced in, private and societal objectives are aligned.

Market based policy instruments contain much more guarantees than technology regulation measures that the overall allocation of emission reduction efforts is cost efficient. Figure 3 illustrates this point. Assuming that nuclear, coal and gas technologies cause environmental externalities, and renewable energy sources do not, we can easily trace out the marginal *social* cost curve of electricity production. The difference in marginal external costs between gas and coal are so substantial in Figure 3 that these technologies switch position in the cost curve compared to Figure 2. If electricity producers are confronted with these external costs, for instance by means of externality taxes or tradable emission permits, then they will prefer to use gas over coal technology in Figure 3. The advantage of this system, compared to an outright ban on coal fired power plants, is that the mechanism can easily adapt to changing market

3 See also the contribution by Fischer (2010) in this book.

Are green subsidies desirable environmental policy instruments?

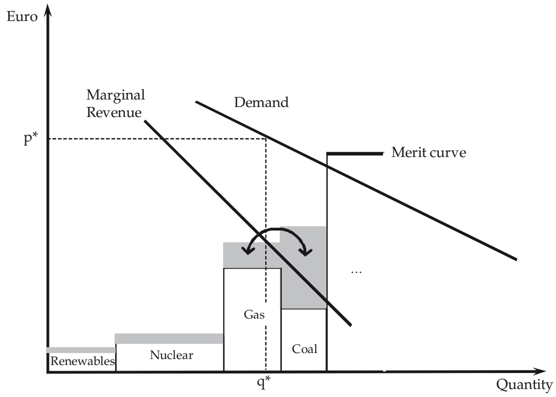
In principle, also subsidies for emission reduction measures can foster cost efficiency. However, economists are usually weary of subsidies because (1) they are expensive (usually, distortionary taxes on for instance labour are required to raise the necessary budget for the subsidies) and (2) if badly designed, they are implicit subsidies for consuming the underlying good or service. Government subsidies for the development of nuclear reactors lead to lower production costs and ultimately consumer prices of electricity. Hence, they stimulate consumers to use more electricity and to care less about energy efficiency. Also, there exist a lot of examples where massive subsidies have led to market distortions, worse than the original externality they were intended to cure, as the following quote from The Economist (2008) illustrates: *America's huge ethanol subsidies, for instance, have led to overinvestment in the businesses, which is now experiencing a sharp bust, and have helped drive up the price of food, with painful consequences for the world's poor. Germany's generous solar subsidies covered the roofs of one of the world's most sunless countries with solar cells, thus pushing up the price of silicon and reducing the cost-effectiveness of solar power in countries where it actually makes sense. Both subsidies promoted the wrong technologies; both wasted taxpayers' money.* [italics added]

For all of these reasons, many environmental economists are no strong supporters of green subsidies. Some, including the OECD (2005), even suggest that cutting down "harmful" subsidies (like subsidies for coal production for instance) could generate cheap environmental benefits. This does not imply that all kinds of green technology subsidies should be banned. Fischer (2008) discusses this issue in more detail.

However, from a politicians point of view, subsidies are attractive because (1) they allow to serve special interest groups and (2) giving, instead of taking away, money is likely to foster one's popularity and hence re-election chances. During the recent recession, green subsidies gained some attention and were seen as means to foster both economic recovery and a transition towards a more greener economy. However, even in these circumstances, the fundamental criticisms explained higher, continue to apply.

conditions. If the market price for gas relative to coal increases, the picture can reverse and electricity producers have an incentive to adjust their production plans in the appropriate way. A technology ban would not be able to adjust as easily to changing market conditions.

Figure 3: Price and production level when externalities are internalized



As for security of supply, the selected policy instruments should also aim at the optimal use of price signals to steer the long run producer and consumer decisions. As security of supply is a public good that will be undersupplied if left to private initiative only, some form of government intervention is required. In the short run, some additional instruments can help to mitigate the immediate implications of supply interruptions. Short run security of supply can for example be enhanced by a coordinated use of energy stocks, redirected supply flows or demand side management. These latter measures all have the purpose to alleviate the immediate consequences of physical interruptions of energy supplies. Also for these short run measures, the goal should be to direct scarce supplies to their most highly valued applications. In the long run, the best possible strategy for a country to guarantee security of supply is to diversify its energy sources. Public support for investments in transmission networks (electricity or gas) with neighbouring countries or, for instance, a LNG terminal would be one option to achieve this.

4. Implications for nuclear power

In the previous paragraphs we argued that good reasons exist for policy makers to intervene in energy markets. Market power, environmental externalities and security of supply arguments warrant intervention but this intervention should not result in mandating which technology should, or should not, be used. Rather, regulation should make sure that all, i.e. private and external, costs are being correctly attributed to different electricity generation technologies. It was argued that with respect to electricity generation, environmental damage and security of supply are two of the most important reasons for government intervention. In this section, we will briefly discuss how nuclear power contributes to (solving) these market failures, which is equivalent to identifying the major elements that differentiate nuclear from the traditional technologies.

4.1 Security of supply

Recent definitions of security of supply distinguish four dimensions: availability (geological presence), accessibility (geopolitical elements), acceptability (environmental elements) and affordability (economic elements), see Kruyt, *et al.* (2009). In this contribution, we only consider availability and accessibility as elements of security of supply. Essentially, nuclear power contributes to both. The third and the fourth dimension, acceptability and affordability, will be covered separately.

Availability

The first and probably the most agreed upon dimension of security of supply is that of the *availability* of resources. According to BP (2009), the existing economic reserves (i.e. exploitable in a profitable way) of oil and gas will last for 3 to 5 decades, assuming current consumption levels. For coal, the situation is better: it can be found worldwide and, at current consumption levels, reserves are sufficient to cover demand for more than a century. For uranium resources, at current consumption levels, economic reserves are sufficient for at least 100 years[4]. In addition, it is possible to reprocess nuclear fuel (recycling) and to use thorium as fuel for nuclear plants. This would delay exhaustion of the stocks with several hundreds of years. In short, in terms of available reserves of fuel, nuclear power plants face no large problems.

Accessibility

The second dimension of security of supply is the geopolitical dimension or *accessibility*. Accessibility focuses on the economic, social and political stability of the countries and regions that own natural resources. Oil and gas reserves throughout the world are mainly concentrated in a relatively small number of countries, most of them concentrated in the same region (the Middle East). Moreover, these countries try to reinforce their market dominance by coordinating their decisions. The OPEC cartel, and the recent attempt to create a similar organization for gas-producing countries, are examples of this. In Europe, the gas conflict between the Russian federation and the transit countries Ukraine and Belarus are another example of the vulnerability of the European economies for Russian gas supplies. The best way to mitigate this vulnerabi-

4 EU Energy Portal http://www.energy.eu.

lity is diversification. This can be done in a number of ways: diversifying over supplying countries is one way, diversifying over technologies is a second one (Morbee and Proost (2010)).

Accessibility was probably one of the major drivers for energy policies in the seventies. The two oil crises have indeed shown in a painful manner that national economies were very vulnerable because, for their energy supplies, they depended almost exclusively on fossil fuels originating from a limited number of countries.

Table 3: Uranium production and resources

	Share of resources %	Share of production %
Australia	23.0	21
Canada	7.7	23
United States	6.2	4
Namibia	5.0	7
Niger	5.0	8
South Africa	8.0	1
Kazakhstan	14.9	16
Russian Federation	10.0	8
Uzbekistan	2.0	6
Ukraine	3.6	2

Source: NEA (2008)

Nuclear power contributes to the availability as well as to the accessibility dimension. On the one hand the available uranium resources are geographically well scattered throughout the world, which is in contrast to the oil reserves and to a lesser degree to the gas reserves, see Table 3. Because of this, the impact of a regional conflict on the uranium supplies is strongly reduced. Several important producers are OECD countries where the political situation is considered to be very stable. On the other hand our dependence on fossil fuel technologies (and thus fossil fuel reserves) is also reduced when using nuclear power. Clearly, the latter is not an exclusive characteristic of nuclear power but also applies to locally produced renewable energy. The bottom line is that, the wider the portfolio of primary energy sources that is used, the less dependent one becomes of single energy sources.

Finally, note that, in comparison with traditional fossil fuel plants, only relatively small quantities of fuel are necessary to run a nuclear power plant. The high energy density of nuclear fuel makes that transport and storage of the fuel can be organized easily. For example, it requires 1kg of coal to generate approximately 3kWh of electricity. With 1kg of oil one produces approximately 4kWh of electricity and with 1kg uranium 50.000 kWh of electricity. Because of this, most nuclear plants are refuelled only once a year so that they have a strategic uranium stock integrated in the power station.

4.2 Acceptability

Some authors see acceptability as another dimension of security of supply. However, we prefer to consider acceptability separately. In our view acceptability refers to the environmental impact of using energy, to the public perception regarding particular technologies and to the threat of terrorism. The environmental impacts are diverse and relate to emissions of – among others – SO_2, CO_2, NO_x and particulate matter, but also to waste and accident risks resulting from the electricity generation process.

Emissions

In its most recent report on climate change, the Intergovernmental Panel on Climate Change (2008) concludes that the "*Warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice and rising global average sea level*". Moreover it concludes that *"most of the observed increase in global average temperatures since the mid-20th century is very likely* (+90% probability) *due to the observed increase in anthropogenic GHG concentrations"*. The IPCC estimates that CO_2 emissions should be reduced to about 13 Gt per year in 2050 in order to keep the average temperature increase within acceptable ranges. With a worldwide emission level of 27 Gt in 2005 and a business as usual estimate of 60 Gt of emissions in 2050, this implies that annual emissions should be reduced dramatically, even compared to current emission levels.

The IPCC study also shows that about a quarter of CO_2 emissions originates from electrical power plants. It is therefore clear that the power sector should also contribute in reducing worldwide emissions. In order to do this, the set of alternative policies to reduce CO_2-emissions in power generation is limited. Essentially, one could take measures to reduce electricity demand, one could capture CO_2 that is produced while generating electricity or one could increase the share of primary fuels with low carbon content in the electricity generation mix. With respect to the last option, two alternatives are available:

increase the use of renewables or increase the use of nuclear. Both produce low emissions of CO_2 when compared with fossil fuels.

Clearly, nuclear power alone will not be sufficient to close the estimated emission gap between the business as usual level of 60 Gt and the target level of 13 Gt in 2050. Increased efficiency in the production and use of electricity, renewable energy sources, carbon capture and storage, and an expansion of the nuclear capacity will all be required to reduce CO_2 emissions sufficiently.

Nuclear power also has an advantage over other fossil fuels when it comes to other types of emissions such as sulphur dioxide and particulate matter. In terms of emissions, the major disadvantage of nuclear power is radioactive emissions. However, from an overall perspective, it has been calculated that nuclear power is one of the most effective power production technologies for avoiding *emission*-related health effects (NEA (2008), p. 114).

Windfall profits from free carbon permits

In Belgium, and probably also in other European member states, there is currently a debate on the electricity companies pricing the cost of CO_2 emission permits into the sales price of electricity. Since 2005, large combustion installations of fossil fuels, hence also fossil fuel power stations, are covered by a European system of tradable carbon emission permits, the so-called ETS (Emission Trading Scheme). For more details on this system, we refer to the contribution of Eyckmans and Rousseau in this book. In most EU member states, including Belgium, the electricity producers have been allocated “short”, meaning that they received less permits than their actual emissions of carbon. These permits were mostly grandfathered, i.e. given for free, to the electricity producers.

Most power producers have passed through the price of carbon to their consumers via an increase in the sales price of electricity. The debate revolves around the observation that power companies charge consumers for the extra cost of carbon although they received a large fraction of the required emission permits for free. For instance, according to Belgian electricity market regulator CREG, the Belgian power producers would have made a windfall profit of about €1,665 million over a period of five years because of these free carbon emission permits, see CREG (2010a).

We would like to make two observations about this argument. First, it should not come as a surprise that power producers price the cost of carbon into the sales price of their product. Economic theory tells us that cost increases will be passed through to consumers relatively more if demand for the product is more inelastic. Demand for electricity is typically rather price insensitive (in the short run, consumers have almost no alternative) and hence a high pass through rate is to be expected. Moreover, the fact that most of the permits were given for free does not mean that they would have no opportunity cost. Instead of using the permits to cover emissions of their own installations, the permits could have been sold at the prevailing permit price and this constitutes a clear opportunity cost for a profit maximizing firm. There are also indications that power companies have seriously taken into account the cost of carbon in their daily operations. Since 2005, emissions of carbon have a price in the EU that power producers have to take into account when deciding on the use of their fossil fuel fired power plants. Delarue, *et al.* (2008) estimate that fuel switching from coal fired to gas fired power plants accounted for a reduction in CO_2 emissions of about 88 and 59 MtonCO_2 in the whole of the EU power sector in 2005 and 2006 respectively.

Secondly, environmental economists are happy that some of the external costs of carbon are reflected in the consumer price of electricity. In fact, that is what we want in order for consumers to change their behaviour and switch to more energy efficient appliances or limit their overall consumption of electricity. Price signals including charges for environmental externalities are crucial to give incentives to users of polluting goods and services to change their behaviour and to achieve ambitious climate policy targets in the future. Therefore, we believe that a high pass through rate is rather a blessing than a curse.

Waste treatment

An important issue in the context of nuclear power is the treatment of nuclear waste. Several categories of nuclear waste can be distinguished, ranging from low to highly radioactive waste. Each waste category requires another type of treatment but the largest scientific and technical challenge is to find safe processing techniques and procedures for the highly radioactive part.

The risk of contamination (radioactivity) decreases over time but, depending on the type of waste, the length varies between a few hundreds of years up to more than 100,000 years. In terms of volumes, the largest part of the waste flow is composed of low- to medium-radioactive waste. The volumes of highly radioactive waste are relatively small, even though they contain as much as 95% of produced radioactivity. Proponents of nuclear power consider the concentrated volumes as an advantage, as this allows storing the waste in geographically concentrated areas, which in turn allows permanent and easy supervision of the nuclear waste volumes.

The largest scientific and technical challenge lies in finding a method for conditioning the nuclear waste, which offers a sufficient guarantee for the environment and public health, not only for current but also for many future generations to come. Two options are available to process the nuclear waste flow. The first is to recycle part of the nuclear waste to be reused again as nuclear fuel. The advantage is that the waste flow can be reduced with a factor 5. The disadvantage is that the reprocessing of nuclear waste requires an extra number of treatments and operations, among others the transport to the reprocessing site. This increases the risk of accidents and thus imposes an extra cost in order to reduce this risk to a minimum. The second alternative is to treat the nuclear waste without recycling and to store it, after a cooling period of at least 50 years (at the surface), in deep geological formations.

Until a few decades ago, the first alternative with maximal recycling was preferred. However, the additional risks (transport to reprocessing factory, the proliferation of plutonium) and the resulting extra costs have brought the second alternative at the foreground again[5]. Moreover, in the public debate, (the risks of) nuclear waste treatment, much more than the accident risk of nuclear electricity generation, is seen as an issue, which brings us to the public perception problem discussed in the next section.

In our view, nuclear waste is the most problematic issue related to the use of nuclear energy. Storing such hazardous waste for many thousands of years is problematic since we cannot control how future societies will deal with it. Chances are high that wars or other major social crisis will affect the storage sites somewhere in the distant future. However, this cannot be much of an argument against the continued use of nuclear energy. Since humankind has already been using nuclear energy for several decades, considerable amounts of highly radioactive waste are currently waiting for a permanent solution. Keeping existing nuclear power plants open for a longer time than initially planned, will only add to an already existing stockpile of waste. Very costly geological storage sites will have to be (and are already being) build anyway, independent of the question whether we continue to use nuclear energy or not. Given that these storage facilities have to be build anyway, the marginal cost of storing additional waste from future nuclear energy use is small.

Given the huge costs involved, it seems to us that there are important economies of scale in the storage of nuclear waste. However, current legislation forces every country to find a solution for its waste within its own territory. From an international perspective, this restriction causes huge extra costs and it is not clear to us that it would enhance the overall safety of the storage.

5 See for example MIT (2003), The Future or Nuclear Power: An interdisciplinary MIT study, Massachusetts, p. 180. French experts however seem to rather prefer the first path.

We therefore plead strongly for more international collaboration, and even trade, in nuclear waste such that waste can be stored in the geologically most suitable and safe locations at the lowest (but still huge) cost possible. Of course, strict government control is necessary to avoid that nuclear waste would be dumped in countries that have not the appropriate means to treat and store it safely. The bottom line of our argument is that the artificial restriction to store one's own waste, increases costs strongly and does not always lead to a safer storage.

4.3 Other acceptability issues

Public perception

For policy makers it is difficult to ignore the population's attitude regarding nuclear power. In a democratic state, preferences of citizens should count of course. But, one should realize that, among other things, this attitude is formed by what people know, or think they know, about the different aspects of nuclear energy (safety, nuclear waste management, proliferation, environment impact, available alternatives, …).

The question is whether the attitude and perception of the general public is based on sufficient and correct information. Surveys show that respondents are not always well informed when it concerns energy and the use of energy. Supplying additional and correct information to the respondents often results in revised opinions and preference reversals. Research shows that in the US the attitude towards nuclear power is mainly driven by the perception of the public with regards to nuclear waste, security and the costs of the technology. In addition, the research shows that the public opinion does not see the link between nuclear power and the greenhouse gas problem.

Concerning risk attitude, it is well documented in the literature, see for instance Hanley, *et al.* (2007), that people tend to overestimate low risk situations (risk of living near a nuclear power plant) and underestimate high risk situation (risk of driving a car). Also, psychological experiments show that people strongly dislike situations that cannot be controlled (compare travelling by an airplane versus driving a car oneself for instance).

All these elements might lead to a biased public perception of nuclear energy. We therefore believe that there is still an important role for government agencies to provide correct and objective information about all aspects of nuclear (and other) energy sources. Leaving this information provision to the stakeholders themselves typically results in a polarization between advocates and opponents and biased information campaigns. But, many observers also conclude that a shift in public opinion pro nuclear can only be realized to the extent that the nuclear industry succeeds in improving the nuclear technology, such that the waste problem and the safety problem is solved or reduced as much as possible[6].

Target of terrorism

Since the terrorists' attack of 11 September 2001, the argument of the threat of terrorism against nuclear installations has frequently been used. On the one hand the danger exists that terrorists would choose an existing nuclear plant as a target. On the other hand there is a fear that radioactive material would fall in the hands of terrorists, who could then produce a so-called dirty bomb. In The Economist of 16 October 2003, Mohamed El Baradei, head of the International Atomic Energy Agency (IAEA) and, together with Hans Blix, leader of the UN observers in Iraq, expressed his concern regarding the wide dispersion of nuclear weapons and radioactive material (El Baradei (2003)).

Against the first argument, the possibility that an existing nuclear plant would be the target of an attack by terrorists, proponents of nuclear power respond by saying that nuclear plants have to obey to very strict construction and safety standards. The plants are constructed such that they can bear the crash of a large plane without radioactivity leaking into the environment. On the other hand, opponents have doubts on the level of construction standards that is being imposed on the construction of nuclear plants. Beyond doubt, the events of Nine-Eleven will lead to more stringent construction standards for nuclear installations in the future.

Regarding the second argument, the possibility that terrorists can put their hands on radioactive material, Mohamed El Baradei pleads for increased efforts in international monitoring of civil nuclear plants, for the development of techniques and technologies that make it difficult to steal radioactive material or waste from nuclear applications, and for more intense international cooperation regarding storage and monitoring of nuclear waste.

In our opinion, decisions taken by individual governments of EU countries will contribute very little to a solution for the security risk. Decisions must be taken and solutions should be agreed upon at the international level, with strict monitoring by independent organization like the IAEA and Euratom. Within these international organizations, individual countries should actively work towards and contribute to developing solutions in line with El Baradei's proposals. The problem with nuclear material is mainly related to badly

6 See MIT (2003), The Future or Nuclear Power: An interdisciplinary MIT study, Massachusetts, p. 180.

monitored civilian and military nuclear installations in former centrally planned economies. More international assistance is needed in order to clean up these sites and store the nuclear material in safe places under internationally recognized supervision. As with the nuclear waste problem, we are convinced that a nuclear phase out will not reduce the risk of terrorist attacks on nuclear installation or the threat of a dirty bomb. Even if all nuclear energy would be phased out, a large number of decommissioned reactors and nuclear waste repositories will have to be protected from terrorist attacks of theft of nuclear material. In economists' language, the marginal effect of a nuclear phase out on the threat of terrorism is close to zero.

5. Assessing the private and external costs

A correct evaluation and assessment of the cost of the energy system is important. This requires that the above mentioned elements are correctly valued and taken into account. In section 3, we argued that policy makers should leave technology choices to the private sector and should limit themselves to giving correct price signals, which implies that current and future private and external costs are taken into account. Moreover, as these costs are spread over time, the time value of money becomes important, which raises the issue of discounting.

5.1 Private costs

When assessing the private cost, two cost elements should be considered: investment costs and operational and maintenance costs.

Investment costs

A nuclear plant is more costly to build compared to a traditional coal or gas plant. According to IEA (2005), per installed kW of generation capacity, a PWR (Pressurized Water Reactor) nuclear plant, costs approximately €1,500. One kW of generation capacity in a coal or gas plant costs approximately €1,250 and €600 respectively. In terms of investment cost per kW, nuclear is clearly more expensive but this disadvantage is largely compensated by the relatively low fuel cost of nuclear plants.

The higher investment costs for nuclear plants make that these plants are interesting only if they have very low operation costs. Next to some technical reasons, this is one of the major reasons to use nuclear plants for base load generation. With the exception of short maintenance periods, nuclear power plants usually operate continuously. However, other options exist to produce base load power. From a technical point of view, it is perfectly possible to replace the nuclear base load capacity by for example gas or coal plants. But, as a consequence, CO_2 emissions would increase strongly.

Antagonists of nuclear energy often propose the use of renewable energy and combined heat and power (CHP) as an alternative for the nuclear plants. However, currently, these technologies cannot take over the role of nuclear plants to produce base load for two reasons. First of all, the effective available capacity of many renewable energy sources (wind, hydro, biomass and photovoltaic applications) depends on weather conditions and is therefore uncertain. Even if a nuclear plant would be replaced by a large scale wind farm, then one should at the same time foresee in backup capacity via traditional large scale coal or gas plants. These backup plants must generate electricity in the periods with little wind or sun. Secondly, the investment costs of many renewable energy technologies are relatively high ranging from about €1,700 / kW for offshore wind farms to more than €4,000 / kW for photovoltaic solar energy according to IEA (2005).

Fuel, operational and maintenance costs

Apart from investment costs, private costs also include fuel, operation and maintenance costs. Under normal assumptions regarding life span and availability, the cost of one 'nuclear' kWh covers 70% capital outlay, 10% fuel charges and 20% operation and maintenance costs. For a coal or gas plant, the share of fuel charges in the kWh costs can increase to 45% and 80% respectively according to IEA (2005). The IEA study reports a wide variety of different technologies for different OECD countries and it is difficult to summarize the private cost estimates in one number. But, generally speaking, the IEA study shows that a kWh of electricity can be generated most cheaply using nuclear, followed by coal, gas, wind and solar energy sources. However, this ranking depends on many assumptions, in particular the prices of gas and coal are crucially important for the ranking of nuclear, gas and coal technology. Compared to other studies (for instance the ExternE study[7]), the IEA (2005) estimates tend to use relatively high prices for fossil fuels which explains the comparative advantage of nuclear energy in their results.

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7 See the ExternE website: http://www.externe.info/ for details. It should be noted that all monetary values of the ExternE study refer to 1998. A recent and extensive comparative study by the Belgian energy regulator CREG (2010b) retains a value of €5.08/MWh as central estimate for the external costs of nuclear energy.

5.2 External costs

In order to assess the full social costs of electricity generation, we also need an estimate of external costs. Several studies have assessed the importance and the size of external effects caused by electricity generation. In this respect, the pioneering European ExternE study is an important reference point. This project developed methodologies to value external costs related to energy production technologies and applied them to several EU member states. The study assesses and values the external effects related to different electricity generation technologies, including nuclear, and reports on external cost estimates under different hypotheses concerning discount rates, time horizon, estimates of future climate damage etc. An important conclusion from this study is that external effects from electricity generation are non-negligible and highly different for different generation technologies.

ExternE estimates of external costs

According to the ExternE (1999) results, the lowest external costs per MWh of electricity production are associated with the renewable energy sources wind (€1.5/MWh) and photovoltaic solar (€2.4/MWh). Next in the order comes nuclear energy with approximately €4.5/MWh, against €17.4/MWh for a gas fired power plant and up to more than €56/MWh for traditional fossil fuel plants using coal or oil[8]. The ExternE estimates are shown in Figure 4. The numbers quoted higher are the averages of the different individual country and installation estimates in ExternE (1999). In the graph we also report the maximum and minimum values. The reason for the large spread for fossil fuel plants has to do with the precise technological details. A gas fired combined cycle power plant (STAG plant) is more efficient and produces therefore less external costs per MWh of electricity production than a more traditional gas fired plant equipped with only a gas turbine.

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8 See CREG (2010b).

Figure 4: External cost estimates (ExternE (1999))

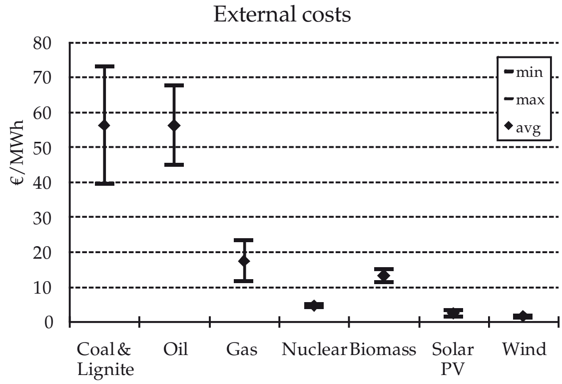
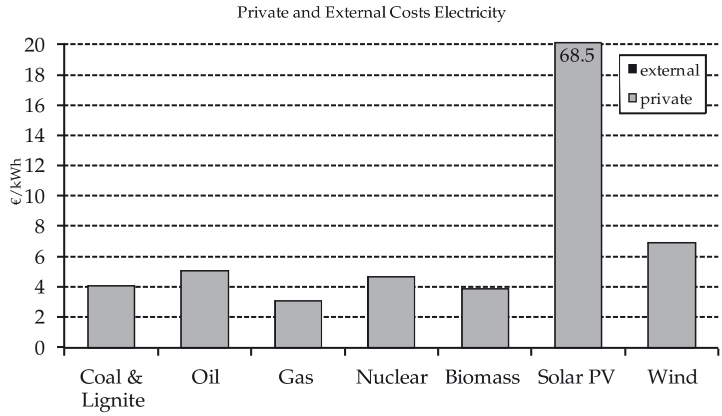


Figure 5 reports the combined private and external costs of electricity generation technologies according to ExternE (1999)[9]. As we can see, gas, nuclear and biomass are comparable in terms of social costs and are the cheapest energy sources from a societal point of view. Nuclear is the most expensive of the three in terms of private costs only but makes up for that disadvantage by its modest external cost. Private costs of wind energy have fallen (and are expected to fall further in the future) as more experience is accumulated with the technology. Wind energy is therefore becoming a competitive alternative to the three cheapest sources. Other fossil fuel based technologies (oil and gas) are less interesting from a societal point of view because of their relatively high external costs. Finally, photovoltaic power is much more expensive than any other technology. Even if prices of PV cells drop even further in the future, their relatively low power output makes it very expensive to produce one kWh of electricity. PV technology is therefore, from a societal point of view, to be considered as a marginal technology but with some interesting niche applications.

9 Note the difference with Figure 2 in which only marginal costs (mainly fuel, operational and maintenance costs) were shown because it refers to the short run decision problem of using existing energy power plants. Figure 5 refers however to the long run in which one has to decide whether and what type of power plants to build.

Figure 5: Full social cost estimates ExternE (1999)



Many caveats apply to these numbers. For instance, private cost estimates are subject to considerable uncertainty of, mainly, fossil fuel prices and the external costs depend strongly on the assumed shadow cost of carbon emissions. One also has to take into account that some renewables shown here are cheap (for example, onshore wind along the cost) but have limited potential, such as, for example, inland wind power which is much more expensive. Also, other arguments than mere costs should play in the choice of technology, for instance base load power and security of supply arguments. As a comparison, a more recent MIT study (footnote 6) gives qualitatively similar results. According to this last study the capital cost and the operational costs (without taking into account external costs) of nuclear plants are higher than those of gas fired STAG plants, even with high gas prices. However, when the external cost of greenhouse gases is taken into account, nuclear power becomes more competitive. But as a general conclusion, we can say that: (1) nuclear power is among the cheapest electricity generation technologies, even when taking into account external costs, (2) renewable energy from biomass and wind has become a more competitive source of power supply, (3) gas and oil fired power plants have comparable private costs but they are characterized by high external costs compared to nuclear, gas, biomass and wind, and (4) photovoltaic power is much more expensive and its share will remain marginal in the overall technology mix.

Extreme damage at accidents

The nuclear accident in Chernobyl has made the public opinion very sensitive for accidents with nuclear plants. In theory, techniques are available to assess the external cost of accidents as long as sufficient observations are available from the past. However, in the case of nuclear power this is not possible. With the exception of Chernobyl (1986) and Three Mile Island (1979), no nuclear accidents have been documented and reported. In practice, one then proceeds to risk-assessment where experts give their judgment concerning the accident risk in each step of the nuclear generation process. This was the approach taken in the ExternE study mentioned before. The resulting cost estimate is in the range of €10.4/MWh down to less than €0.2/MWh for accidents with less serious radioactive contamination. We should also point out that not all expected accident costs are to be considered as external costs. Electricity generating firms are, at least partially, subject to liability regulation in the case of damages caused by an accident (Percebois (2003)). This liability ensures that at least part of the accident costs are already included in the private electricity generation costs. Only that part of the accident costs which exceeds the costs covered by the liability regulation, must be considered as an external costs.

Experts in cost-benefit analysis will point out that the traditional methodology of assessing expected costs (expected damage equals the probability of an accident times the total damage) is problematic for situations in which very small probabilities of an accident are combined with very large damages. In decision theory, this problem is known as the Sint-Petersburg paradox which was described in 1738, by the Swiss mathematician Bernoulli. Entering into the details of this paradox would lead us too far, but the paradox is frequently quoted to question the use of the expected value concept for assessing the risk of situations in which large damages go together with extremely low probabilities[10]. However, this point was also addressed in the ExternE methodology by considering various degrees of risk aversion.

Decommissioning

The private cost of nuclear plants already includes – some will say partly – provisions for the decommissioning of nuclear plants and the processing of the nuclear waste. As a rule of thumb, NEA (2003) states that decommissioning a nuclear plant would cost 10 to 15% of the investment cost. Currently, Belgian electricity generators are contributing to a special fund to finance the cost of decommissioning and of nuclear waste storage[11]. These financial contributions have been settled via the electricity price and, consequently, are not to be considered as external costs. Whether these provisions are sufficient to cover all future costs remains open for debate. In any case, these decommissioning costs, which are external costs for traditional plants and (at least partially) internal for nuclear plants, have been (partly) taken into account in

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10 The solution proposed by Bernoulli is to use a concave transformation rather than the expected damage itself. However, this procedure also has its problems. The interested reader is referred to http://plato.stanford.edu/entries/paradox-stpetersburg.

11 See CREG (2001). This is a study concerning the provisions and funds in the nuclear sector that can be downloaded from the CREG website: www.creg.be.

the investment decision process of the generation firms. It is only to the extent that this fund is insufficient to pay for the nuclear waste treatment and the decommissioning, that the extra costs should be attributed as external costs to the nuclear sector.

Discounting

Assessing the cost of nuclear waste treatment is difficult because the storage costs extend over a very long period of time. In cost-benefit analysis, the traditional way to take into account the time value of money is via discounting. This technique starts from the assumption that people prefer one euro today rather than one euro next year. For this reason, when calculating the total sum of all costs and benefits over many periods in time, weights smaller than one are given to future monetary values. These weights decrease as the costs or profits are situated further in the future. For example, a discount rate of 3% (this is the discount rate used in the ExternE study) would imply a weight of 0.000,000,015 for a costs of 1 million euro to be paid in 1000 years. In other words, large costs in the distant future are wiped out almost entirely by the traditional discount method. For this reason it is important to assess the sensitivity of the cost-benefit approach for changes in the value of vital parameters, such as the discount rate. For example, the ExternE study presents external cost estimates for discount values ranging between 3% and 0%. But questions remain, even with a discount rate equal to zero. For example, Kneese and Schulze (1985) argue that using discounting for problems such as nuclear waste is not neutral for the normative framework within which the analysis happens. In particular it is argued that discounting is justified only under very restrictive hypotheses, among others the possibility to compensate future generations for possible damages they would suffer in case a nuclear storage site would start leaking.

However, discounting problems are not unique for nuclear power, they also occur when other electricity generation technologies that produce greenhouse gases are assessed. Nuclear power causes long term problems because the highly radioactive waste needs to be stored hundreds of thousands of years before the radiation level falls back to an acceptable level. With greenhouse gas emissions, future climate changes will result in environmental damage that falls upon future generations in the coming centuries. In other words, the claim that the valuation of the long run consequences of nuclear waste is impossible, actually also applies to technologies based on burning fossil fuels. Consequently, this argument does not allow to discriminate between nuclear power and more traditional electricity generation methods.

5.5 One cannot have it all the same time

The major drivers for the renewed interest in nuclear are its potential contribution to a *climate change* solution and to improved *security of supply*. We argued before that both issues justify government intervention. However, realizing both objectives will put an upward pressure on the cost of electricity production. At the same time, there is also a political pressure to reduce energy prices for end-users as it is perceived by politicians that the electricity market liberalization increases efficiency and thus creates room for price reductions. Many politicians find that the liberalization of energy markets has failed in this respect and that firms charge too high prices. Consequently, political pressure is large to impose upper limits on these prices. It is obvious that the *climate change* and *security of supply objective* are likely to be incompatible with the objective of lower electricity prices. Phasing out nuclear would only contribute to the incompatibility by limiting the available technological options to achieve CO_2 emission reductions and security of supply. Surely, and especially in developed economies, a nuclear phase-out can technically be implemented and absorbed but one should not expect at the same time a decrease in the cost of electricity.

Although, we are not aware of any study that looks into the cost impact of achieving both a GHG emission reduction target and a security of supply target together with a ban on nuclear, there are a number of studies that assess the cost impact on the energy system of phasing out nuclear in the presence of a GHG emission constraint. Imposing an additional security of supply constraint would only further increase the cost of a nuclear phase out.

Belgian perspective

Several Belgian studies have attempted to make an overall evaluation of the cost evolution of the Belgian energy system when nuclear power is phased out[12].

From this study it appears that, for the specific Belgian context and taking into account private as well as external costs, nuclear power is one of the cheapest technologies for the production of electricity. The study mainly takes into account environment-related external costs and the accident risk. Other elements pro or contra nuclear, such as its contribution to security of supply and base load production, increased risk of terrorism and proliferation and the negative public perception are not considered in this exercise.

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12 See the report of the Commisie voor de Analyse van de Productiemiddelen van Elektriciteit en de Reoriëntatie van de Energieverctoren aan de Staatssecretaris voor Energie en duurzame Ontwikkeling (Ampere Comissie (2000)). and Bossier, *et al*. (2008)

As mentioned before, it is – from a technical perspective – perfectly possible to replace the nuclear production capacity by traditional plants. Simulation exercises with the MARKAL/TIMES model show that, *without* Kyoto obligations, this can even be realized at an almost negligible costs for the Belgian economy[13]. In that case, the cost efficient solution implies that mainly coal plants would be built to replace the nuclear capacity. However, when emission constraints for GHG and other pollutants are taken into account, this shift is less obvious. Antagonists of nuclear power point out that alternative policy options are available at the demand as well as at the supply side of the electricity market. At the supply side renewable energy, combined heat and power (CHP) and distributed generation are alternatives. At the demand side the rational use of energy (energy efficiency) is the main option.

The use of renewable energy as an alternative for the nuclear plants has been discussed before. An increased use of CHP no doubt has some potential in Belgium, but the use of CHP should be coordinated with applications that require heat. CHP applications without heat demand are meaningless.

Taking demand reducing measures can slow down the increase in the demand for electricity. It is to be questioned whether it is realistic to assume that rational energy use (REU) measures are able to bend the electricity demand in a structural and fundamental way. Moreover the costs (capital outlay, but also for example the loss of comfort for end-users) of REU measures should be considered when assessing their contribution.

We can therefore conclude that, for Belgium, it is technically perfectly possible to phase out nuclear energy without jeopardizing the supply of electricity to households and industry. However, it should be noted that in the simulation exercises, nuclear power stations are often replaced in the future by coal fired plants that are equipped with carbon capture and storage CCS technology. This conclusion depends of course on the estimated cost and date of availability of CCS technologies. In particular, it was assumed that this technology would be available by 2025 at a competitive cost. However, many observers argue that this is too optimistic.

Global perspective

Vaillancourt, *et al.* (2008) use a bottom up technology model of the MARKAL type (World-TIMES) to assess the long-term role of nuclear power in the world

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13 See Proost and Van Regemorter (2001). These resaearchers estimate the cost of realizing a post-Kyoto a reduction target of -15% emission (in 2030) relative to the 1990 emissions at 0.5% up to 1% of the GDP if nuclear plants are not phased-out. The cost of achieving the same reduction target with a nuclear phase-out is estimated at 3% of GDP if no international trading in emissions or electricity is allowed.

energy system if constraints are imposed on CO_2-concentrations. The authors consider two concentration scenario's both to be realized in 2100. The first scenario assumes a global atmospheric CO_2 concentration constraint of 550 ppmv in 2100, the second one assumes a more stringent concentration target of 450 ppmv. World-TIMES is an optimisation model coupled to a detailed database of energy technologies and estimates of regional resource availability. The model minimizes the total cost of satisfying price elastic demand for energy services over a horizon of 100 years (2000-2100) in a multi region setting.

Their analysis shows a growing role for nuclear energy in the long run, especially at the stringent 450 ppmv level. At the same time, traditional fossil fuel power generation technologies lose market share. In the long run, new fossil fuel technologies, for instance coal fired power station equipped with carbon capture and storage CCS technology, enter the technology mix. Also renewable energy sources play an important role to satisfy energy demand in the future energy system under a carbon emission constraint. Moreover, Vaillancourt, *et al.* (2008) also show that limiting the role of nuclear in achieving the CO_2-emission reduction target, would significantly increase the total cost of the world energy system.

In general this, and similar studies like for instance Bosetti, *et al.* (2009), show that at a global scale, nuclear energy is important in the future to meet growing energy demand, especially in rapidly growing developing countries like China and India. Moreover, these studies also show that there is no fundamental conflict between nuclear and renewable technologies. Even when allowing for nuclear energy, renewable energy sources will gain a substantial market share and will become important sources of power production in many regions across the world.

6. Conclusion

In this contribution we have reviewed the most common arguments that are used in the debate on the phase out of nuclear energy in many European countries including Belgium. We felt it was necessary to do this because the public discussion in Europe is strongly polarized between opponents and proponents of the nuclear energy option. In our view, the discussion should be based on rational and correct arguments and data and we hope to have contributed to an informed public debate.

We argued that all electricity generation technologies should be faced with their correct social – i.e. private and external – costs. Internalizing external costs (and benefits) by means of emission taxes, contributions to decommissioning funds etc, is crucial to align private and public interests. In our view, and many other energy and environmental economists, there is still room for considerable improvement in this respect.

Once all production technologies are confronted with their correct social cost, economists believe there is little reason for the government to prohibit some technologies or prescribe others. It should be left to the electricity producers to select the optimal mix of generation technologies to be used because they have an important informational advantage over the government to make these choices. As long as all relevant social costs are internalized, it is difficult to argue for government intervention. We therefore do not plead for less government intervention, but rather for a more intelligent intervention that makes electricity producers responsible without patronizing them. This way of acting will probably be more easily accepted by the parties concerned and might even allow to pursue more ambitious environmental objectives.

Of course, our argument crucially depends on a reliable estimate of all relevant external costs of electricity generation. In the last decade, considerable progress has been made in this domain, both methodologically and empirically. The estimates (original and updates) of the European ExternE project are an important and reliable reference in this respect. Their estimates show that there are important external costs associated with the use of nuclear energy. However, these costs are small compared to the costs of traditional fossil fuel fired power plants, especially when taking into account future climate change damages from greenhouse gas emissions. Low external costs, combined with relatively low fuel cost, make nuclear energy a viable technology from a societal point of view. It should be noted that this does not jeopardize the market potential of combined heat power or renewable energy sources like wind and biomass. These technologies have the strong advantage of low external costs and often add to security of domestic energy supply. Independent of the role of nuclear, some renewable energy technologies will carve out an important market share in electricity market in the future.

Especially at the global level, exclusion of nuclear energy from the future portfolio of electricity generation technologies, would have severe consequences for energy supply in fast growing developing countries like China and India. Without nuclear energy, they will rely more on their cheap and plentiful coal resources for base load electricity generation. This would have a very strong impact on global greenhouse gas emissions and resulting climate change.

For developed economies in Europe and North America, things look somewhat different. Studies show that both future electricity demand and international greenhouse gas emission ceilings can be respected without resorting to nuclear energy. However, it should be clear that it is impossible to achieve three objectives at the same time: low greenhouse gas emissions, no nuclear power and low electricity consumer prices. Trade offs are to be made. Especially if one aims at deep cuts in greenhouse gas emissions in the future, the costs of a nuclear phase out will increase. Whether societies are willing to incur that cost, is ultimately a political question. We can only provide rational arguments for an informed and open public debate on this issue.

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EU-Objectives on Climate Change and Renewable Energy for 2020 in Belgium[1]

Wouter Nijs
VITO
Denise Van Regemorter
K.U.Leuven, Centrum voor Economische Studiën

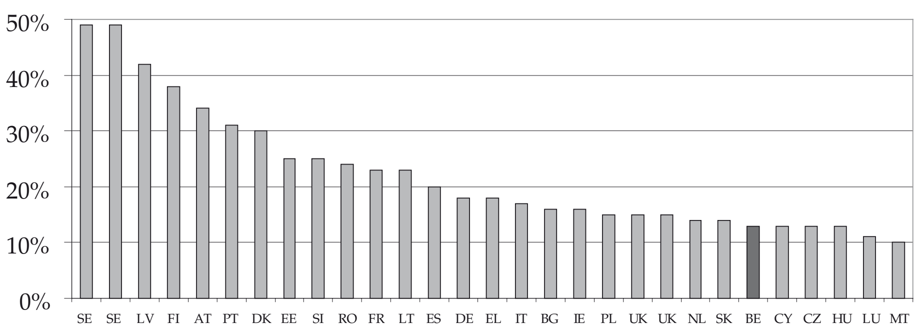
1 This research has been funded by the Belgian Science Policy, (SSD III) project 'TUMATIM, Treating Uncertainty and risk in energy systems with TIMES'. It has also benefited from the development of TIMES and the associated software VEDA within the EU research project 'NEEDS' (NEEDS 2008)

1. Introduction

In this chapter we analyze the impact for Belgium of the EU-objectives for climate change and renewable energy for 2020. In January 2008, the European Commission published its impact assessment on the EU-objectives for climate change and renewable energy for 2020. The European Commission decided, in its "Climate action and renewable energy package" (EC, 2008), to reduce the EU GHG emissions by 20% by 2020 in comparison to 1990, to have a 10% share of biofuels in transport and a 20% share for renewables in 2020.

For climate change, a distinction is made between the ETS sectors with the emission trading system at EU level and the non-ETS sectors with targets at country level. The EC has decided on an EU target for the ETS with auctioning of the permits and a burden sharing between countries for the non-ETS sectors to reach the overall 20% reduction target. The renewable target is also allocated between countries. The specific targets for Belgium are a reduction of 15% CO_2eq in 2020 compared to 2005 for the non-ETS sectors and a renewable target share of 13% in 2020 (figure 1). In addition, there is a target for renewable energy in the transport sector of 10%[2].

Figure 1: Renewable target for EU countries in 2020



This chapter analyzes the renewable energy target for Belgium and its interactions with the climate policy targets. The issue is studied with the Belgian TIMES model.

In the first section of this chapter, the model is explained, in the second section, the different scenarios developed for this analysis are described. In a third section the results are analysed and the final section concludes.

2 In this analysis simplified to a biofuel target

2. Model and methodology

TIMES is a techno-economic optimisation model which assembles, in a simple market context, technological information (conversion efficiency, investment and variable costs, emissions, etc.) for the entire energy system. The model is developed within an IEA Implementing agreement, ETSAP, in which Belgium participates (Loulou et al, 2005). The Belgian version of the model was developed by CES-K.U.Leuven and VITO with the financing of the Belgian Science Policy Office (Van Regemorter and Nijs, 2007 and 2008)

The model maximises the sum of consumer and producer surplus inside the energy system using linear programming. It can simulate the energy demand and supply activities with technological detail for a country and also provides information on associated emissions and environmental damage. The model uses a horizon of up to 40/80 years. In the Belgian version, the time horizon is 2050. The demand functions for energy services are a function of the activity levels per sector and the cost of energy services. The energy services (passenger car km or steel) are produced in the most cost effective way, combining demand side technologies (more energy efficient light bulbs, more efficient car engines etc.) and supply side technologies (better power stations or refineries). In this way one is able to simulate the potential role of new technologies in the energy supply and demand in a sector.

The model is dynamic and forward looking in the sense that all choices (use of energy services as well as types of technologies) take into account the costs and benefits over the whole lifecycle. The discounted welfare includes the benefits to all users and producers of energy as well as all variable and investment costs of delivering energy.

3. General assumptions and Reference Scenario

3.1 Background Assumptions

The starting point is the construction of the reference scenario. It is important to stress the role of this scenario for policy analysis with the TIMES model. The reference scenario has not as objective to forecast the development of the energy system. It gives a consistent development path for the energy system, using a cost optimisation approach and the simplified representation of the energy users and suppliers behaviour in TIMES. The reference scenario serves as basis to evaluate the cost of policies and their impact on the technological choices in the energy system. The reference scenario can therefore deviate from the evolution of the energy system in recent years which reflects the real behaviour of the economic agents, their expectations and the dynamic adjustment of the energy system. The main advantage of our approach is therefore a consistent treatment of the technologies for policy evaluation.

The construction of the reference scenario is based on assumptions regarding the macroeconomic evolution for Belgium and the World energy prices evolution till 2050 complemented with energy policy assumptions.

Macroeconomic assumptions

The macroeconomic background for Belgium was derived with GEM-E3, a general equilibrium model for the EU countries. It gives the economic growth rates used for deriving the energy service demands in the reference scenario. The demand functions are obtained by applying assumptions on the elasticity of the sectoral demand with respect to the macroeconomic evolution. The international energy prices are those derived in July 2007 with the POLES World energy model by IPTS (Russ et al, 2007), a research centre of the European Commission, updated with the assumptions in the PRIMES model for the EU impact assessment.

Table 1: Macroeconomic Assumptions for Belgium and international energy prices

	Unit	2010	2015	2020	2025	2030	2035	2040	2045	2050
Population	%/y	0.2%	0.2%	0.2%	0.2%	0.2%	0.1%	0.0%	-0.1%	-0.1%
GDP	[4] %/y	2.2%	2.4%	2.2%	1.8%	1.7%	1.6%	1.5%	1.3%	1.2%
Import price crude oil	€/GJ	7.8	8.6	9.1	9.6	10.5	11.3	11.7	12.7	13.6
Import price natural gas	€/GJ	4.1	4.9	6.1	7.5	7.6	8.2	9.1	9.6	10.9
Import price coal	€/GJ	2.0	2.1	2.3	2.5	2.6	2.8	3.0	3.2	3.4

Renewables potentials

Potentials for renewable resources are an important element in the evaluation of the EU targets. The production potential of the different renewables used in the model are those proposed by De Ruyck for the ‘Commissie Energie 2030’ (De Ruyck, 2006). For biomass, it is assumed that 10% of the arable land in Belgium can be used for the production of biocrops, such as wheat or rapeseed and 30% of the forest for the production of wood. Both types of biomass can also be imported. A limit is imposed on their imports though Belgium as a small country could benefit from an unlimited supply. Moreover, the supply

3 The years actually refer to a period in which all model yearss are equal, in this case: 2008-2012
4 All costs and prises in this paper are in €2010

is assumed to be available at an increasing cost by considering two price steps to reflect the pressure of demand when a climate policy would be applied in the whole EU.

For wind energy a distinction is made between on and off shore. The cost of the grid expansion needed for the implementation of the full potential of offshore is included in the cost of the power plants[5]. The data related to the wind technologies and the potentials were also checked with (Devriendt et al., 2005).

The table hereafter summarizes the potentials assumed for the different sources.

Table 2: Potential for energy sources

		Domestic	Import
Biomass (PJ)	Wood residue	10.8	
	Wood	22.7	25-83
	Biocrops (wheat & rapeseed)	16.5	25-83 for each crop
Wind (GW)	Onshore cat1	0.63	
	Onshore cat2	0.92	
	Onshore cat3	0.47	
	Offshore cat1	0.60	
	Offshore cat2	0.30	
	Offshore cat3	2.90	
Solar (GW, GWth)	PV	10	
	Hot water	3	

Carbon capture and storage could be an important option when a high reduction target is imposed. Geological disposal in deep aquifers and coal sinks is modelled for the storage of the removed CO_2. A maximum cumulative potential of 100 Mt of CO_2 at a distance less than 20km and of 1000 Mt at higher cost is considered. This potential is present in Belgium (Laenen et al., 2004). The 100 Mt can be captured with high certainty in Belgium; 1000 Mt is uncertain (although, if not in Belgium, this could represent foreign sinks).

5 As TIMES is not running in mixed integer mode, binary investment options are not possible. The cost is therefore included as a cost per Kwe installed; therefore the cost computation is only correct if the full potential is installed.

General policy assumptions

In the reference scenario, there are no major changes expected in the Belgian economic, energy and environmental policies. The nuclear phase-out is implemented. The EU emission trading system (ETS) is assumed to be in place and to impose a price of 24 €/ton CO_2 after 2015. It has been assumed for this modelling exercise that the sectors covered by the ETS would include all the industrial sectors and the electricity sector as this seems to reflect the actual tendency of enlarging the sectoral participation[6]. This leaves for the non-ETS sectors the residential, service and transport sectors.

In all scenarios, the discount rate is fixed to 4%, reflecting the public sector approach in the policy evaluation with TIMES. Policy measures like subsidies for energy efficient investment or similar measures implemented in the different regions are not explicitly accounted for. We do this to guarantee a consistent comparison of the technologies. It must be mentioned that in the reference scenario, the perfect foresight/optimisation approach in TIMES can already induce the use of some of the policy-promoted options even in the absence of any carbon constraint, as long as they are cost-efficient (the 'no-regret' options). Moreover, the assumption regarding the carbon value for the ETS in the reference induces also a shift towards less carbon intensive technologies.

3.2 The Reference Scenario

Given the demand functions for energy services, TIMES optimizes the choice of energy processes, the energy efficiency, the choice of fuel by the energy users as well as the choice of energy production processes by the energy sector. The choice is based on the information on the present and future availability of energy technologies, their costs and performance at the level of the energy user and at the level of the energy producer. It is clear therefore that the energy path as derived from this optimisation process, takes into account all the no-regret options and may therefore slightly underestimate the real growth of the energy demand. Other criteria besides cost minimisation driving consumer behaviour are not reflected in this reference.

The primary energy consumption grows on average at 0.5%. There is a shift to solids when coal power plants replace the nuclear power plants. Oil products keep a relatively high share of the energy market because they remain the dominant fuel in the transport sector. Renewable energy , with a market share of 0.8%, does not really penetrate and is actually lower than today's share of renewable energy because the model is calibrated to the 2000 data.

6 The model does not allow to make a distinction between small and large installations in the non energy intensive sectors.

In Flanders, the share of renewable energy was about 2.9% in 2009 of which 1.0% green electricity, 1.3% green heat (mainly wood stoves) and 0.6% biofuels (Aernouts K., 2010).

Table 3: Primary Energy Consumption in the reference scenario (abs. in PJ and % share)

	2010	2020	2030	2040
Coal	377	683	1013	1133
Oil	1123	1145	1264	1381
Natural gas	645	583	569	523
Nuclear	505	350	0	0
Hydro, wind, photovoltaic	8	14	14	14
Other renewables	12	12	12	12
Waste	16	20	21	23
Total	**2685**	**2808**	**2893**	**3085**
Coal	14.0%	24.3%	35.0%	36.7%
Oil	41.8%	40.8%	43.7%	44.8%
Natural gas	24.0%	20.8%	19.7%	16.9%
Nuclear	18.8%	12.5%	0.0%	0.0%
Hydro, wind, photovoltaic	0.3%	0.5%	0.5%	0.4%
Other renewables	0.4%	0.4%	0.4%	0.4%
Waste	0.6%	0.7%	0.7%	0.7%

The evolution in the primary energy consumption implies that the CO_2 emissions linked to energy increase. In 2020, they are 26% above the level of 2005 and continue to increase thereafter, especially after 2025 when coal power plants should replace the nuclear power plants. Industry and transport remain the biggest emitters in the first period but the electricity sector becomes an important polluter when new coal power plants are installed.

Table 4: CO_2 emissions in the reference scenario (Mio.ton and %)

	2010	2020	2030	2040	share 2010	share 2020	share 2030	share 2040
Industry[7]	48	59	64	70	40%	39%	35%	35%
Hous, Com & Agr	27	23	22	19	22%	16%	12%	9%
Transport	25	26	28	31	20%	17%	15%	15%
Electricity	17	37	67	76	14%	25%	36%	38%
Other supply	5	5	5	5	4%	3%	3%	2%
Total emissions	122	149	186	200	100%	100%	100%	100%

4. Construction of the scenarios

To evaluate the effect of the EU targets for Belgium, we consider 4 scenario's, including the reference scenario. The Belgian Kyoto target and the nuclear phase-out are imposed in all scenarios. It is assumed that 7% of the reduction target in 2010 is achieved by buying permits abroad. Only CO_2 emissions are considered as the other GHG are not yet modelled and the energy system is only responsible for a small part of the other GHG. Some variants have also been considered for the analysis, but they are only mentioned further in the text for reasons of clarity. Table 5 reproduces the definitions and the specific assumptions for the different scenario's.

Table 5: Scenario definitions and assumptions

Scenario	Definition
REF	Reference scenario with a CO_2 price for ETS-sectors of 24 €/t after 2020
REN	Same as REF + 10% biofuel target + 13% Renewable target
CLIM	A CO_2 price for ETS sectors of 39 €/t in 2020 and a CO_2 emission constraint for non-ETS sectors
CLIM_REN	Same as CLIM + 10% biofuel target + 13% Renewable target

Scenario	Assumptions	Years		
		2010	2020	2050
REF and REN	CO_2 price for ETS sectors (€/ton)	20	24.2*	24.2*
CLIM and CLIM_REN	CO_2 price for ETS sectors (€/ton)	20	39.1*	208
	CO_2 constraint non-ETS sectors (ref = 2005)	-8%	-15%	-39%**
REN and CLIM_REN	Biofuels target		10%	10%
	Renewable energy target		13%	15%

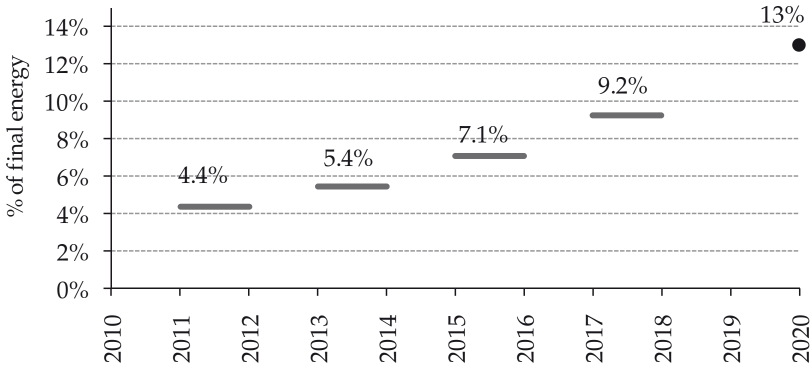
* These values come from the Impact Assessment report of the European Commission on the Climate and Renewable Action Plan (EU, 2008); **Corresponds to 8 Mton extra reduction in the non-ETS sectors in 2050, compared to 2020

"REN" refers to the biofuel and renewable target imposed. Figure 2 gives the renewable target for Belgium from the EU and the minimum trajectory. In the model, targets were explicitly modelled only for 2015 and 2020. The formula for the computation of the renewable target % in the model is:

- As numerator: electricity and heat (from CHP) produced by renewable technologies + renewable energy (not electricity or heat) in the final demand sectors

- As denominator: total electricity and heat (from CHP) produced and total final demand (not electricity and heat)

Figure 2: Renewable target for Belgium and minimum trajectory



For technologies such as heat pumps, the implicit energy from air or ground was not taken into account although this energy is considered as green energy in the renewables Directive. However, the advantage of reducing the final energy by increasing the share of heat pumps, is incorporated in the model.

The scenario "CLIM_REN" is close to current EU climate policy. In this scenario, the targets for the non-ETS sectors have been implemented. The model assumes an EU-wide CO_2 price for the ETS sectors in line with the EC impact assessment (EC, 2008) in which a European model was used.

As TIMES is a perfect foresight model, it is important to take into account the future beyond 2020. It was assumed that the effort for GHG reduction would continue, given the EU objective of limiting the temperature increase to no more than 2° Celsius. A carbon value gradually increasing to 208 €/ton CO_2 in 2050 was imposed on the ETS sectors and a reduction target of 37% for the non-ETS[7] compared to 2005. For the renewable target, a share of 15% was imposed after 2020 while the biofuel target remains at 10%. The importance of these two specific targets decreases with the stringency of the climate target, as will be seen in the results.

8 The target for non-ETS and the ETS carbon value were fixed such as to achieve a certain convergence between the non-ETS and ETS carbon value by the end of the horizon.

5. Results

5.1 The energy system welfare cost

The total welfare cost of the alternative scenarios is shown in table 6 and 7. The cost is the additional cost of alternative scenarios in comparison with the reference scenario. As the level of demand for energy services can change, the welfare cost equals the change in the sum of consumer and producer surplus. It does not take into account possible side benefits through the reduction of other external costs linked to energy use. Neither does it include the derived effects on other markets which depend on the policy instrument used[8].

The result in the first column of table 6 is the relative change of the total discounted energy system cost in TIMES over the entire modelling period until 2050. The result in the second column shows this cost as a ratio to the estimated GDP for Belgium in 2010 (Eurostat).

Another way of representing the additional cost is to annualise it with a discount rate of 4% and then relate it to the estimated GDP of 2010, as shown in the next table. This is a yearly equivalent annual cost. The additional cost varies from year to year as shown in the last columns.

Table 6: Total discounted welfare cost (loss of consumer/producer surplus), compared to REF

	%DIF	%GDP2010
REN	5.5%	1.4%
CLIM	16.2%	4.2%
CLIM_REN	17.5%	4.5%

Table 7: Total annualised (averaged) welfare cost and undiscounted welfare cost

	Annualised [M€]	Annualised %GDP2010	Undiscounted cost [M€/an]		
			2020	2030	2040
REN	853	0.25%	1702	1736	2008
CLIM	2518	0.73%	1898	5860	8610
CLIM_REN	2719	0.78%	2770	6171	8803

8 Changes in the tax revenue and the costs specifically associated to the change in market distortions in other sectors - Cf. double dividend literature.

It can be seen from the results that the CO_2 reduction scenarios CLIM and CLIM_REN are close in terms of cost. Imposing a renewable target on top of the climate target increases the total system cost but the additional cost is limited. The cost increase is not more than 0.05 % of GDP2010 in annualised terms (see table 7). This additional cost corresponds, on average, to an increase of the energy system cost by some 8%. In terms of the annual system cost in 2020, the cost increase is much higher. The additional cost in 2020 increases from about 1.9 B€ to 2.8 B€, an increase of nearly 50%. However, it still represents only 4% compared to the reference in 2020. After 2020 the annual additional costs remain small.

This is also reflected in the renewable shadow price in table 8. For 2020, the marginal cost of the renewable target is in "CLIM_REN" almost equal to the marginal cost in the scenario "REN" where there is no climate constraint. The renewable target of 13% is clearly dominating the climate target here. The CO_2 price for the non ETS sectors (the shadow price of the CO_2 constraint) is even zero in 2020. The reason is that the renewable target is forcing the CO_2 emissions below the target for the non-ETS sectors. If there is no renewable target, the shadow price of the non-ETS target has a price of 22 €/t CO_2. Apparently, there are some cheap options in the non-ETS sectors for the renewable target, mainly reducing the final energy demand in the commercial sector. The CO_2 price for the ETS does not change as it was assumed fixed.

After 2030, the renewable shadow price is very low. The reason is that renewable energy is, in the longer term, a cost efficient option when climate policy is the only objective.

Table 8: Shadow price of the targets and CO_2 price imposed in the ETS

	2010	2020	2030	2040
Shadow price of renewable target (€/MWh)				
REN	0	55	46	63
CLIM_REN	0	56	0	2
Shadow price of CO_2 constraint non-ETS (€/t CO_2)				
CLIM	29	22	117	150
CLIM_REN	30	0	92	159
Shadow price of biofuel target (€/MWh)				
REN, CLIM, CLIM_REN	0	0	0	0
Price of CO_2 ETS (€/t CO_2)				
REN	20	24	24	24
CLIM	20	39	103	155
CLIM_REN	20	39	103	155

The shadow price of the biofuel target is zero: the share of biofuels reaches 12.7%, so above the 10% target. A scenario with only the 13% renewable target and without biofuel target gives the same results. Increasing the share of biofuels is a good option for reducing the CO_2 emissions (shadow price zero in CLIM) and for increasing the renewables share when more stringent renewable targets are imposed. A variant of the CLIM_REN scenario was created with only the biofuel target, thus without the overall renewable energy target. In this variant, the biofuel target is binding and the shadow price of the constraint amounts to 36 €/MWh in 2020.

A second variant of the CLIM_REN scenario has been constructed to test the assumption of distinguishing ETS and non-ETS sectors. Imposing an overall CO_2 price instead of distinguishing ETS and non-ETS sectors does not influence much the cost. This is an indication that the target of 15% reduction for the non-ETS sectors is close to an overall cost efficient solution. The renewable value decreases from 56€/MWh to 31€/MWh in 2020, because in this variant, the CO_2 emissions of the non-ETS sectors have a price in 2020. The differences disappear rapidly after 2025.

5.2 CO_2 emissions and energy consumption

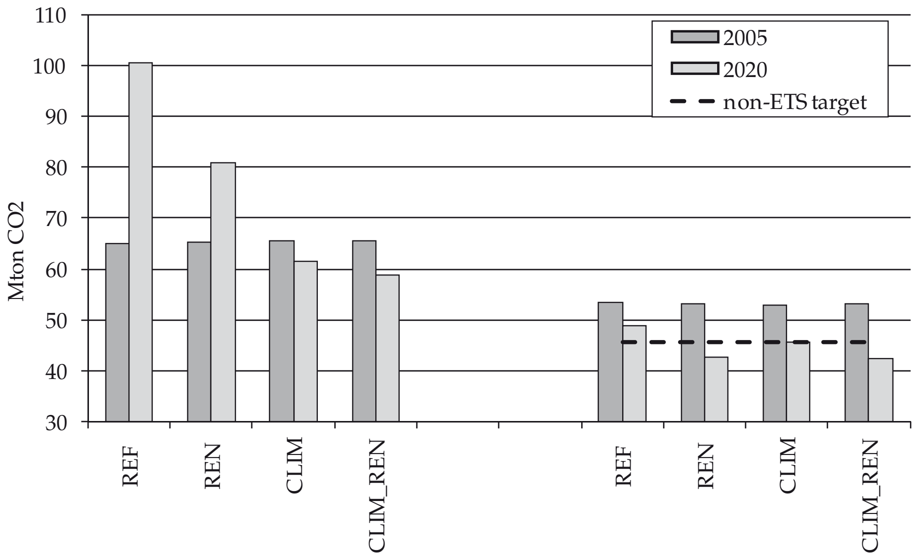
The CO_2 emissions for the different scenarios are given in the table below. The CO_2 emissions are not reduced much when only the renewable and biofuel targets are imposed without any climate target, especially in the long term. A policy targeted only on renewable energy alone is not enough for the climate target as it does not induce a sufficient CO_2 emissions reduction. Adding the renewable target to the climate policy reduces the emissions in 2020 with an additional 4%-point.

Table 9: CO_2 emissions in the different scenarios (in Mio.t and percentage reduction)

	2010	2020	2030	2040
REF	122	149	186	200
REN	121	124	161	173
CLIM	119	107	89	80
CLIM_REN	119	101	87	79
REN	-1%	-17%	-14%	-14%
CLIM	-3%	-28%	-52%	-60%
CLIM_REN	-3%	-32%	-53%	-61%

The contribution of ETS and non-ETS sectors in these emission reductions is analysed in the figure below. Both ETS and non-ETS sectors contribute to the reduction target, except in the REN scenario.

Figure 3: CO_2 emissions in the ETS (left) and non-ETS sectors (right)



The primary energy consumption decreases with the climate target and there is a substitution away from coal to gas and renewables. The shift towards renewables is more pronounced when there is a specific renewable target.

Table 10: Primary energy consumption (PJ) (difference compared to reference)

	CLIM				CLIM_REN			
	2010	2020	2030	2040	2010	2020	2030	2040
Coal	-15	-422	-799	-958	-15	-430	-813	-970
Oil	-24	-12	-53	-99	-24	-65	-72	-100
Natural gas	20	213	368	443	20	84	340	412
Nuclear	0	0	0	0	0	0	0	0
Biomass, hydro, wind, photovoltaic	0	48	164	248	0	240	256	273
Waste	0	0	0	-1	0	0	0	0
Total	-18	-173	-319	-366	-19	-171	-289	-386

The share of renewables (as computed for the renewable target) is given in the table below. Here again one can see the impact of the renewable target in 2020 where the share is more than doubled. After 2020, the climate target leads by itself to an increase in the renewable share without however going much beyond 13%.

Table 11: Share of renewables (computed as for the renewable target)

	2010	2020	2030	2040
REF	1.1%	1.4%	1.3%	1.3%
REN	1.2%	13.0%	13.7%	14.4%
CLIM	1.2%	4.3%	9.8%	12.7%
CLIM_REN	1.2%	13.0%	13.7%	14.4%

5.3 Technological options for renewable energy

Imposing a renewable target leads mainly to a more rapid penetration of the technologies based on renewables, such as biomass for heat and CHP. In the electricity sector, the full potential for wind off shore of 3800 MWel is used from 2020 onwards. A very high growth rate of the capacity of wind turbines off shore is needed in such scenario. In the absence of a renewable target, part of the emission reductions in the electricity sector were obtained through carbon capture and storage and these are replaced by emission reduction through renewables whenever a renewable target is imposed.

When the target for renewable increases, biofuels for transport are penetrating more rapidly, first ethanol and then biodiesel[9], until the maximum potential is used.

The potentials imposed on domestic production for biocrops and wood play an important role in these results and should be further examined with sensitivity studies.

Table 12 gives the results for the CLIM_REN scenario with a 13% and 20% share of renewable energy. The tables makes a distinction between green electricity (ELC) and other green energy (Non-ELC), thus green heat and biofuels.

9 Mixing biofuels with oilfuels can be seen as a first step to a more generalised use, cars on biofuels being more efficient.

Table 12: Technological option for renewable in a CO_2-scenario with 13% and 20% renewable target in 2020 (PJ)

Scenario	CLIM_REN13		CLIM_REN20	
Process	ELC	Non-ELC	ELC	Non-ELC
CHP Steam Turb. condensing WOOD Chemistry	0.1	0.2	0	0
CHP Steam Turb. condensing WOOD Non Ferro	2.6	4.5	1.5	2.6
CHP Int. Combust. Biogas Other	0	0	0.3	0.5
CHP Steam Turb. condensing WOOD Other	24.1	42.0	7.4	12.9
CHP Int. Combust. Biogas Paper	0.4	0.5	5.9	7.6
CHP Steam Turb. condensing WOOD Paper	4.1	7.1	0	0
CHP Int. Combust. Biogas Refineries	0	0	0.1	0.1
CHP Steam Turb condensing WOOD Refineries	0	0	2.3	4.0
Hydro	1.6	0	1.6	0
Hydro New	0.9	0	0.9	0
PV Plant Size	0	0	31.0	0
Wind Base-year	0.1	0	0.1	0
Wind Offshore Close	6.9	0	6.9	0
Wind Offshore Medium	3.5	0	3.5	0
Wind Offshore Far	33.4	0	33.4	0
Wind Onshore High	5.5	0	5.5	0
Wind Onshore Medium	5.6	0	5.6	0
Wind Onshore Low	1.5	0	1.5	0
Industrial Wood Heating	0	1.5	0	73.0
Residential Wood Heating	0	8.0	0	0
Biodiesel for Transport	0	0.0	0	41.0
Ethanol for Transport	0	44.9	0	44.9
Total Electricity and non-electricity	**90.2**	**108.7**	**107.4**	**186.6**
TOTAL		**198.9**		**293.9**

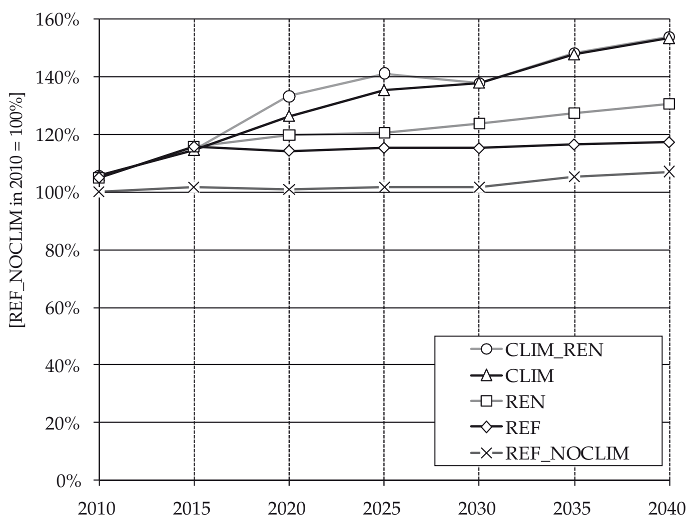
5.4 Impact on electricity price for households

As an example of the impact of the climate and energy policy on the energy price, the evolution in the electricity price in the residential sector is reproduced in the table and graph below. A fix transport and distribution cost is assumed. The total electricity price increases with the stringency of the targets and here again the impact of the renewable target is reflected mainly in 2020 and 2025. The impact of the renewable target is lower than the impact of having the climate policy alone. In contrast to REF, REF_NOCLIM is a scenario without a tax for CO_2.

Table 13: Electricity price for households (compared to 2010 if no climate policy)

	2020	2030	2040
REF_NOCLIM	2%	2%	5%
REF	16%	15%	16%
REN	16%	21%	27%
CLIM	14%	35%	48%
CLIM_REN	15%	41%	48%

Figure 4: Relative electricity price for households (compared to the price in 2000)



5.5 Impact of the renewable target

For a specific evaluation of the renewable target for Belgium, different runs of the CLIM_REN scenario were done with a renewable target going from 10% to 20% in 2020. For the period after 2020, the target is slightly increased as can be seen in the table below. The other policies are assumed fixed.

Table 14: Share of renewable energy

	2010	2020	2030	2040
CLIM_REN10	1.16%	10.0%	10.9%	12.7%
CLIM_REN11	1.16%	11.0%	12.4%	13.7%
CLIM_REN12	1.16%	12.0%	13.0%	14.0%
CLIM_REN	**1.16%**	**13.0%**	**13.8%**	**14.4%**
CLIM_REN15	1.20%	15.0%	15.0%	15.0%
CLIM_REN17	1.21%	17.0%	17.0%	17.1%
CLIM_REN20	1.15%	20.0%	21.7%	23.4%

With the increasing target on renewable, the share of biofuels (which are one of the available options) increases also, as seen in the next table. For a renewable target of 13% or more, the cost efficient share of biofuels is more than 10%. For a renewable target of 12% or less, the cost efficient share of biofuels is less than 10%.

Table 15: Share of biofuels in transport

	2010	2020	2030	2040
CLIM_REN10	0%	10.0%	10.0%	13.6%
CLIM_REN11	0%	10.0%	10.6%	13.6%
CLIM_REN12	0%	10.0%	10.0%	13.6%
CLIM_REN	0%	12.7%	12.3%	13.6%
CLIM_REN15	0%	15.7%	13.1%	13.6%
CLIM_REN17	0%	16.9%	13.8%	13.7%
CLIM_REN20	0%	24.8%	25.3%	26.2%

Table 16 shows the shadow price of the non-ETS CO_2 target. With a renewable target above 13%, the increase in the shadow price of CO_2 is shifted towards the later periods.

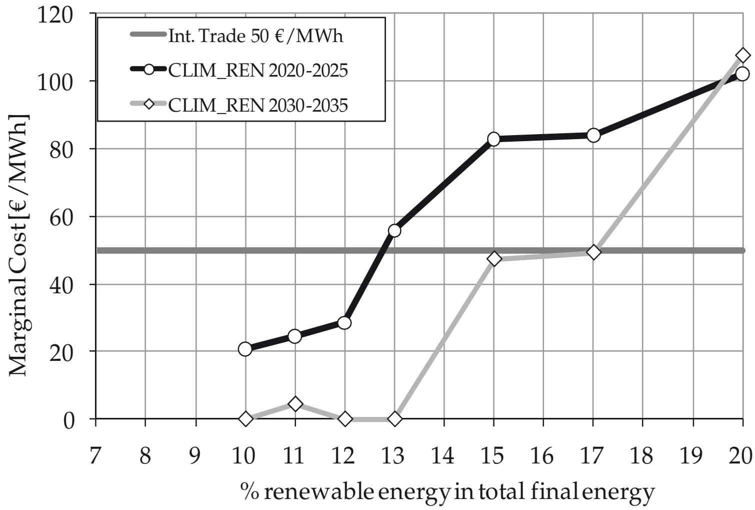
Table 16: Shadow price of the non-ETS CO_2 target (€/ton CO_2)

	2010	2015	2020	2025	2030	2035	2040
CLIM_REN10	29	40	0	39	109	134	157
CLIM_REN11	29	41	0	37	100	133	157
CLIM_REN12	29	41	0	31	110	133	156
CLIM_REN	30	42	0	0	92	133	159
CLIM_REN15	26	35	0	0	35	72	158
CLIM_REN17	26	29	0	0	25	67	161
CLIM_REN20	26	27	0	0	0	0	0

The shadow prices of the renewable constraint are illustrated in Figure 5. The shadow prices increase from 20-30 €/MWh to 90-100 €/MWh when increasing the target to 20%. Beyond 2020, it becomes very costly to impose a target above 13%. Numbers are averaged for the period 2020-2025 and for the period 2030-2035. They represent the marginal cost of an extra MWh of renewable energy that is imposed, given that there is already a CO_2 constraint. The marginal cost decreases over time because of the assumed policy for CO_2, except for a stringent renewable target of more than 17%.

One can also compare these results with assumed prices for a EU-green certificate. Assuming a liquid market in guarantees of origin for renewable energy, there would be one price for a EU-green certificate. For example with an international price of 50 €/MWh, it would be cost efficient to have 13% and 17% of renewable energy in Belgium in respectively 2020-2025 and 2030-2035, given the climate policy imposed.

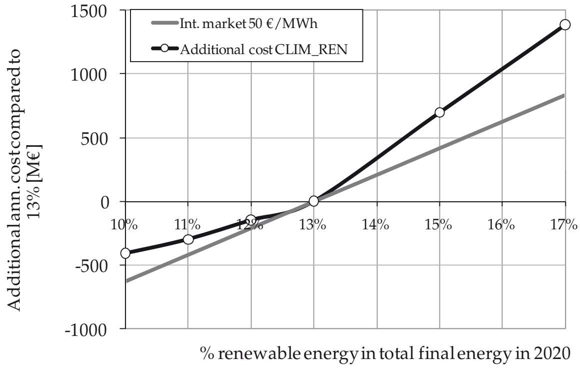
Figure 5: Shadow price of renewable target for the scenario CLIM_REN averaged for 2020-2025 and 2030-2035



In Figure 6, the black line represents the additional annual cost in the year 2020 compared to the situation where a 13% target is imposed. The other marginal cost curve is linear and represents the opportunity cost assuming an international price of a green certificate of 50 €/MWh. The cost of a target for a Member State is after all the price of an international green certificate multiplied with the target. With renewable shares that are higher than 13%, the average additional annual cost for one extra percentage of green energy amounts to 350 M€ (rounded). This conclusion is only valid for 2020, since it has been shown that the marginal cost decreases rapidly after 2025.

These computations have been based on the CLIM_REN scenario that assumes a fixed, exogenous price for the ETS sectors. A fixed price of carbon for the ETS sectors is an important assumption in our policy scenarios where policies overlap. An endogenous carbon price (at EU level) generates different results. Sensitivity analysis with the Belgian model shows that the additional cost of a 20% renewable target is 20% lower. It also shows that the results on the marginal cost for renewable energy are not very different when the carbon price is made endogenous.

Figure 6: Additional annual cost in 2020 compared to the proposed 13% renewable target



6. Conclusions

The conclusions in this chapter are clearly dependent on the modelling assumptions and on the cost and technology assumptions used.

For the total period (2010-2050), the addition of a renewable and biofuel target on top of the climate target increases only slightly the total cost of a climate only policy. This increase is however mostly concentrated around 2020 and can then be substantial compared to the no renewable case. The addition of the renewable target represents an increase of the annual cost of the energy system of some 4% compared to the reference in 2020.

The imposition of the renewable target implies that the non-ETS CO_2 target is achieved without any specific CO_2 emission additional reduction efforts in this sector.

After 2020, the policy for renewable energy only increases slightly the cost of achieving the Belgian climate target as a limited introduction of renewables is part of a cost effective climate policy. As renewable technologies are still in their development phase, the renewable targets could contribute to more innovation in renewable energy and contribute as such to future more stringent climate targets. It could also induce other external benefits (air pollution etc).

When renewable certificates become tradable and one can rely on a long-term European price for green energy certificates of about 50 €/MWh, it would be cost efficient to have 13% and 17% of renewable energy in Belgium in respectively 2020-2025 and 2030-2035, given the climate policy imposed.

The biofuel target in transport is only binding when imposed without the renewable or climate target, the biofuel option being one of the options to reach the renewable target. Its share reaches approx 12% with the renewable target. Though the assumptions regarding the potential for biofuels for Belgium are rather conservative, the side effects of the use of biofuels in terms of biodiversity, food production, etc. if extended at EU / World level need further examination.

A policy targeted on renewable energy alone is insufficient to reach the climate target.

We have shown that the climate and renewable policies interact and that the cost of additional climate or renewable efforts can only be specified when both constraints are clearly specified. While both the climate target and the renewable target contribute to the reduction of the CO_2 emissions, the technological choice they induce can be different, e.g. carbon capture versus electricity production from renewables.

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